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Vol. XVII No. 10 JULY 1, 1946

A MAGAZINE OF METHODS FOR OPERATING MEN

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Editorial

THE TASK now confronts the industry of building up oil reserves and of putting into general practice improved processing and refining methods developed during the war.

A lag in the rate of finding new oil reserves has prompted a scrutiny of prevailing exploration methods. Geophysics is the key to successful exploration. It has been said that geophysicists are neither too optimistic about the possibilities of new methods nor too pessimistic about the possibilities of present methods. Improvements in conventional instruments and techniques now in use may go a long way toward improving the discovery rate. In this connection, the airborne magnetometer is one development of the war that may become an invaluable aid in prospecting.

Some progress has been made in the solution of well spacing problems, which involves an understanding of the principles of reservoir performance and an intelligent application of these principles to the spacing of wells. Improved drilling equipment and methods, including the use of special mud fluids in drilling and completing wells, have been developed that may aid in offsetting rising drilling costs.

Advanced methods of secondary recovery, including water flooding and gas injection, are being studied and applied in practice. The years immediately ahead may witness great progress in this phase of producing operations.

High rates of production necessary to meet wartime needs provided an opportunity for quantitative observation and the evaluation of petroleum reservoir characteristics under controlled conditions.

In the refining branch of the industry, small catalytic cracking units of the latest design that will turn out high grade products at low cost, are now being made available to the small independent refiner.

Some of these important developments are discussed in this issue in a selected list of papers that have special reference value to the reader.

REFERENCE ANNUAL 1946

THE Petroleum Engineer

The Reference Annual is a special number, not one of the monthly issues, and therefore does not carry the regular features. The contents are selected papers of significance that have been presented during the previous year.

Relation Between Well Spacing and Recovery§

By W. V. VIETTI,* J. J. MULLANE,† O. F. THORNTON,* A. F. VAN EVERDINGEN‡

● **Abstract.** The authors conclude that no correlation exists between well spacing and recovery for the Mexia-Powell fault-line fields, and that recoveries obtained by open-flow production from areas within a reservoir cannot be used to derive or substantiate a mathematical relationship between spacing and recovery for the reservoir.

There exists a difference of opinion as to the effect of spacing upon recovery. Some authors contend that there is a mathematical relationship between the two. Such a relationship was recently proposed, based on recovery from the Mexia-Powell fault-line fields A critical review of the information on these fields by the authors shows that the data cannot be used to derive such a formula. The differences in unit recoveries are small, and are attributable to factors other than spacing.

Recoveries from areas of different spacing within a field heretofore have been used to derive or substantiate formulas relating spacing and total recovery. This procedure is incorrect, as the differences in recovery exist because per well-producing rates are not related to the volume of pay or to the recoverable oil attributable to the well. The amount of the resulting drainage cannot be calculated easily, but in some cases may be approximated by assuming equal recovery per well.

The choice of well locations (spacing) should be based upon the principles which govern reservoir performance, and not upon empirical formulas proposed in the early days of the petroleum industry.

● **Introduction.** Experience obtained early in the history of the petroleum industry during the period of "wide-open" production led to a belief that the ultimate recovery from a reservoir depends largely on the number of wells drilled. Careful studies of well spacing, however, have indicated that ultimate recovery is substantially independent of the number of wells.[1a]

In a recent paper Clark, Tomlinson, and Royds[4] revived this early belief. They proposed that well spacing does affect recovery; that increased well density results in increased recovery, and that there is a definite mathematical relationship between the two. This conclusion was based primarily upon data for the Mexia-Powell fault-line fields by Hill and Guthrie[5] and also upon information for the Lucien, Hewitt, Healdton, and Oklahoma City fields in Oklahoma, and the Chase Townsite pool in Kansas. The formula proposed by Clark et al. states that the recovery per acre-foot from a given reservoir is inversely proportional to the square root of the well spacing (acres per well). The formula is a restatement of the Cutler[6] rule.

That such a wide difference of opinion as to the effect of well spacing upon recovery should exist among the well informed is particularly disturbing to management in the petroleum industry and to the layman.

The purpose of this paper is to analyze the basic data used by Clark, Tomlinson, and Royds, and to determine whether a valid basis exists for such a far-reaching conclusion as their proposed square-root (Cutler) rule, particu-

§Presented by Mr. Vietti, at the Twenty-fifth Annual Meeting, American Petroleum Institute, Chicago, Illinois, November, 1945.

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[a] Figures refer to references at end of article.

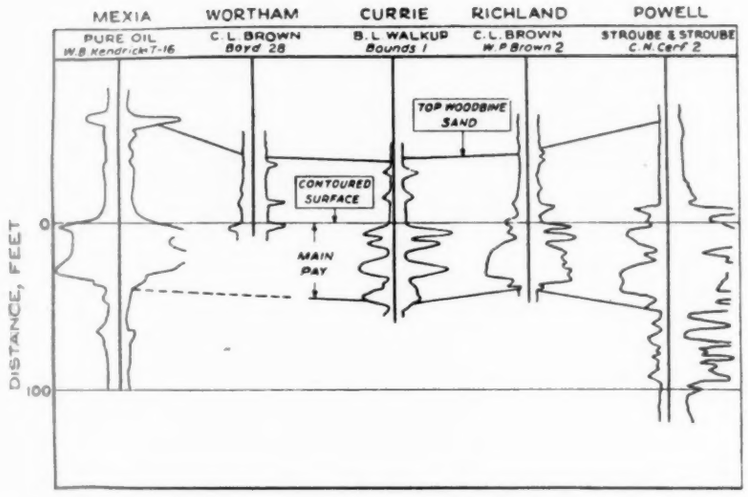


FIG. 1. Cross-section of fault-line fields correlated on top of main pay zone.

larly as it is contradictory to rather well established principles of reservoir behavior.

● **Cutler's rule of well spacing.** Clark, Tomlinson, and Royds refer to the suggestion made by W. W. Cutler[6] in 1924 that per-well recoveries under different spacings are related to the average distance the oil has to move to reach the well. Several factors relative to Cutler's statement should be pointed out.

The intrafield data used by Cutler were from the Nowata, Bartlesville-Dewey, Hewitt, Bartlesville, and Glenn Pool fields in Oklahoma, and the Speechly and Buena Vista Hills fields in Pennsylvania and California, respectively. These were all predominantly dissolved-gas-drive reservoirs, which were in part lenticular and non-continuous. This fact was recognized by Cutler when he stated " . . . it is evident that recovery will be approximately proportional to spacing whenever the primary expulsive force is gas and the reservoir rock is continuous throughout the area under consideration." It becomes obvious on inspection that, when the volume of the oil reservoir is continuously changing as in water or expanding gas-cap-driven fields, relative spacing (density) is secondary to structural position of the wells as a factor in recovery.

Cutler's rule is stated as follows: "The ultimate productions for wells of equal size in the same pool, where there is interference (shown by a difference in the production-decline curves for different spacing), seem approximately to vary directly as the square roots of the areas drained by the wells," or, " . . . is proportional to the average distance that the oil moves to get to the well."

Cutler attempted to approximate differences in recovery between areas of different well density in a common reservoir. Students of this problem today recognize that these differences may exist because of drainage by closely drilled areas of those less closely drilled. Moreover, even though Cutler's rule may be correctly applied to one reservoir, it cannot be applied to recoveries from two or more fields of different spacings. Many have erred in attempting to so use it.

For fields wherein the sand thickness is uniform, Cutler's rule may be restated that the ultimate recovery per acre-foot of sand drained by a well varies inversely as the square root of the area drained by the well. This is the analogue, but restricted to apply only between wells in a given field (total recovery fixed) to the mathematical relationship by Clark, Tomlinson, and Royds proposed to relate total recovery to spacing.

The Cutler rule was reviewed by H. C. Miller and R. V. Higgins[7] in 1939. The following comparative review is based in part on the work of Miller and Higgins.

1. Cutler's rule is based on "wells of equal size." This refers to wells which produced the same quantity of oil for the *first year* under wide-open conditions. It does not refer to prorated production.

2. "The same pool," as used by Cutler, meant not only the same field, but the same reservoir in the same field. Stretching the Cutler rule to cover different fields and to encompass all the reservoirs in one field surely is not a restatement of the Cutler rule.

3. "Interference," as used by Cutler, is defined as "a difference in the production-decline curves for different spacings." Here again a single, continuous, and intercommunicating reservoir is indicated. Cutler recommended (if we may interpret) the drilling of wells sufficiently close so that there would be interference, but did not go beyond the spacing where interference reduced ultimate production per well. His remarks on the Bartlesville-Dewey district are quoted: "In order to properly drain the tracts in this field, the ultimate spacing per well should not be greater than 7 acres." Ultimate production per well became smaller at closer than 7-acre spacings in this district, according to the data presented by Cutler.

TABLE 1—Recovery estimates—Mexia field.

	Upper sands	Main zone	Hill and Guthrie fault leases
Acre-feet of sand	45,500	92,600	103,543
Recovery, bbl.	9,100,000	93,547,000	89,500,000
Unit recovery, bbl. per acre-foot	200	1,010	864
Spacing, acres per well			4.7

4. Cutler also limited his rule to the condition, "whenever the primary expulsive force is gas." Reservoirs studied by Cutler were shallow, low-pressure and, therefore, low in dissolved-gas energy, low temperature, and are low in both porosity or permeability.

5. We quote Miller and Higgins:

(a) "In other words, the recovery of oil from a pool as a whole may not be increased necessarily, because relatively high recoveries are obtained from certain closely drilled tracts within the productive limits of a field." (P. 14, *Bureau of Mines Report of Investigations 3479.*)

(b) "Any assumption that the rule applies in general to all pools, regardless of type and methods of producing them, cannot be accepted as true, because such a supposition fails to take into consideration the dissimilarity and complexity of oil-producing reservoirs and the fact that the behavior of deep-seated, high-pressure reservoirs undergoing depletion differs widely from that observed by Cutler in those shallower, lower-pressure pools on whose performance the tentative rule was based originally." (Concluding sentence, p. 20, *Bureau of Mines Report of Investigation 3479).*

● **The Mexia-Powell fault-line fields.** The fault-line fields, producing from the Woodbine sand in Texas, were discovered in the period 1921 to 1924, and were quickly developed. Encroachment of edge water was early and at a rapid rate. The initial production rate probably exceeded the rate of water encroachment, but the settled production was undoubtedly under water drive. As pointed out by Clark et al., the fields are similar in a number of respects, and they provide the subject of an interesting comparative study. Many of the methods now commonly used to obtain sub-surface information, such as electric logging, core analysis, subsurface sampling and analysis, and bottom-hole-pressure recording, unfortunately were not then in use. Therefore, any study must be based on meager data concerning sand volume in particular.

Some electric logs have been obtained from comparatively recent drilling on local "highs." Those contained in the Hill and Guthrie report number: four in Mexia, one (incomplete) in Wortham, three in Currie and North Currie, two in Richland, and one in Powell. The analysis of only one core sample from an upper Woodbine sand-stringer (not the main pay) was available. Oil-production data by leases, drillers' logs, completion data, and maps showing wells making water were other data given.

To show the features of the Woodbine in the fault-line area, a cross-section has been prepared (Fig. 1) from the avail-

able electric logs; and Fig. 2 of the Hill and Guthrie report, showing a generalized section, has been reproduced. The Woodbine sand has a well defined electric-log pattern of high natural potential and resistivity readings. It will be noted from Fig. 2 that Currie and Richland produce from the "main" pay, which is the first 40 ft. to 50 ft. below the contoured surfaces. Mexia, Wortham, and Powell produce also from stringers above and below the main sand. The Currie field is shown as having a gas cap above the elevation of approximately 2520 ft. below sea level.

Inspection of the data obtained by Hill and Guthrie, and presented in their report, shows a multiplicity of reservoirs in each fault-line field. The presence of continuous shale breaks, "main pay," "big pay," gas zones, upper and lower sands, variable or indeterminate water-oil contacts, substantial differences in gravity, dry holes within the productive limits, and the gauging together of oil from the Morrow or Corsicana and Nacatoch, all make these fields unsuitable for mathematical reservoir analysis.

Clark, Tomlinson, and Royds state that these fields provide the equivalent of a laboratory demonstration of the effect of spacing upon recovery, in that all factors other than well spacing are the same. A review of the data published by Hill and Guthrie shows many other factors were variable between the individual fault-line fields and between pay sands in the same field. The other factors which did influence recovery from the fault-line fields are outlined in the sections which follow. The interpretations by Hill and Guthrie seem to have been based primarily on drillers' logs. The present reviewers do not accept the interpretation of original water-oil and gas-oil contacts or net pay-sand thicknesses in the reservoirs. No correlation between well spacing and recovery remains after allowing for the influence of the other factors. The small differences in unit recoveries are attributable to factors other than spacing. The recovery data cannot be used as the basis for an empirical formula.

● **Mexia field.** Reference to Figs. 1 and 2 shows the Woodbine at Mexia to be composed of an upper pair of thin sands, 7 ft. and 5 ft. thick, and the main sand zone beginning at 2440 ft. below sea level. These sands differed markedly in producing characteristics.

The authors of the *Bureau of Mines Report of Investigations 3712* state on p. 67: "The absence of a water drive in the two upper sandstone strata was recognized early in the life of the Mexia field, and production from these beds probably will be less than 200 bbl. per acre-foot. On the other hand, the main Woodbine producing sandstone was underlain by water, an active natural water drive was recognized in this bed, and the quantity of oil that will be recovered ultimately per unit volume of reservoir rock probably will be three or four times that from the upper two sandstone strata. Therefore, when comparing performance of wells in the Mexia Field with the other fault-line fields, only the data for the main Woodbine producing sandstone should be compared with similar data for the other fields."

The foregoing statement is substantiated by factual data. Reference to Fig. 3 of R.I. 3712 shows that 11 edge wells, beyond the limits of the main sand and, therefore, completed in only the upper stringers, are producing no water. This clearly indicates the absence of water drive. Tables 2 and 3 of the Hill and Guthrie report show the low recovery obtainable from these stringers. The 25 leases, which are entirely outside the limits of the main sand, obtained an average recovery of only 249 bbl. per acre-foot.

TABLE 2—Well data—Wortham field.

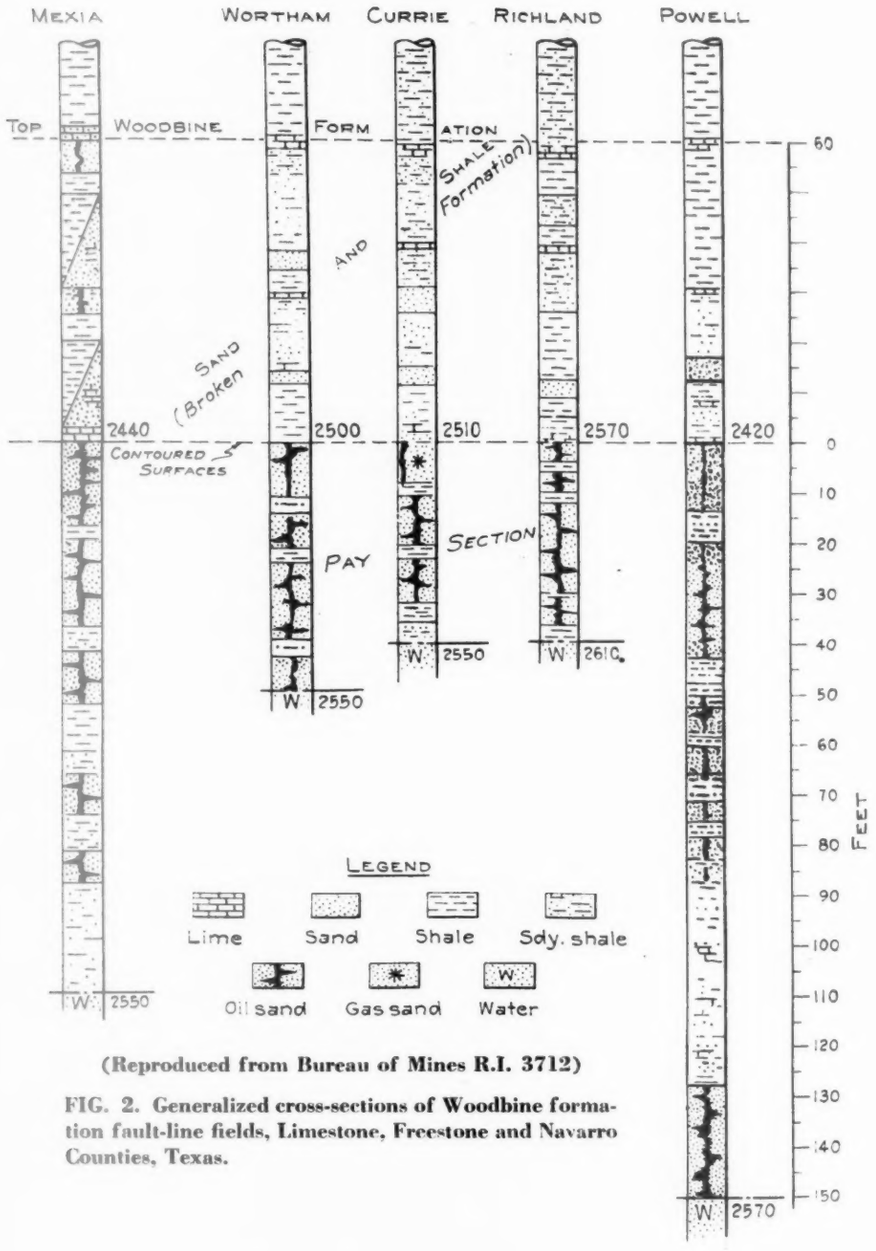
Section and well no.	Total depth, ft. below sea level	Completion date, 1925	Initial production, bbl. of oil per day	Well test data—year 1925			
				Date	Production		Producing method
					oil, bbl.	water, per cent	
Section A'-A							
1	2562	2-17	500	2-20	460	..	F
4	2565	2-15	500	2-20	225	..	F
Section B'-B							
1	2553	2-15	300 (S)	2-20	100	..	F
2	2552	1-16	702	1-26	918	..	F
3	2552	1-3	1506	1-26	882	..	A
4	2555	2-26	100 (S)	3-17	45	..	P
Section C'-C							
1	2542	1-13	7500	1-26	3922	..	A
2	2542	1-7	9000	1-26	2239	..	A
4	2544	2-7	300 (S)	2-20	248	..	P
5	2544	1-22	150 (S)	2-20	200	4	P
Section D'-D							
3	2544	1-25	400	2-20	240	..	P
4	2544	1-11	3000	2-20	185	..	P
5	2545	1-18	1200	2-6	110	37	P
6	2544	1-12	6500	2-20	125	37	P
7	2547	1-11	3000	2-20	115	25	P
8	2544	1-3	2410	2-6	394	..	P
9	2551	1-21	800	1-23	1001	35*	F
10	2555	2-18	75 (P)	2-20	425	9*	P
Section E'-E							
2	2548	1-24	500	1-26	1068	..	F
3	2548	1-1	1200	1-26	1000	..	F
4	2550	1-2	3500	2-20	950	..	P
5	2549	1-21	4152	2-20	1200	6.6*	P
6	2550	2-1	80	2-20	450	40	P

Note: F=flowing. P=pumping. A=agitating. S=swabbing.
*Denotes per cent water and sediment.

Hill and Guthrie used only the "fault leases" at Mexia for comparison with other fault-line fields. The fault-lease wells produced from the two upper stringers of poorer sand as well as from the main sand, and the sand volume used for the fault leases contained the sand in the two upper stringers. A lower than normal recovery per acre-foot from "main" Woodbine sand would, therefore, be calculated. Following the guidance of Hill and Guthrie as quoted hereinbefore, a correction for both sand thickness of and oil produced by the upper sands should be made on the fault leases to approximate the values for the "main Woodbine producing sands zone."

It is indicated that liberal net sand thicknesses for the main zone have been used by Hill and Guthrie. Attention is directed to the character of the zone as shown on Fig. 1 and 2. It consists of a main sand approximately 40 ft. thick which contains some shale breaks, followed by a shale section of some 20 ft., then sand stringers and shale to the base of the section. Particular reference is made to the electric log of Pure Oil Company's Kendrick No. T-16 well, which is located in the center of the lease and structurally high (tract A-15, well "C," Fig. 3, of R.I. 3712). A reasonable interpretation of this log would indicate 8 ft. of sand and 5 ft. of shaley sand or sandy shale in the two upper stringers, 38 ft. of main sand section of which the bottom 3 ft. are shaley sand, followed by 28 ft. of sandy shale, and shale with 4 ft. of sand in a stringer at the base of the section. A total of some 55 ft. of sand, or 42 ft. for the main zone, would be considered optimistic. Reference to Table 4 of the Hill and Guthrie report shows that an average thickness of 74 ft. was assigned to the lease on which this well is located, presumably on the basis of drillers' logs, of which 61 ft. would be attributed to the main zone. The total sand shown by the electric log is only 74 per cent of the average thickness stated by Hill and Guthrie for the lease and, for the main zone, approximately 69 per cent. The log for Peyton Bros. W. M. Harris No. 1 well (well "A," Fig. 3 of R.I. 3712), which is 1800 ft. west of tract A-15, may be similarly interpreted.

Furthermore, the amount deducted for shale in the main zone by Hill and Guthrie appears to be low. Fig. 3 of R.I. 3712 shows contours on top of the main pay. The water level and limiting contour was estimated at an elevation of 2550 ft. below sea level. Also, a limit for the upper stringers was estimated which enclosed a total of 3798 acres (Table 6—R.I. 3712). The contour map has been planimetered to determine the gross volume of Woodbine between the contoured surface and water. The area of 3798 acres was used to derive the acreage constant for the planimeter. The results showed there are 123,500 acre-feet in the gross volume, and that 2760 acres were originally productive. Hill and Guthrie calculated that there were 152,000 acre-feet of net sand in all zones. The two upper stringers must have contained 45,500 acre-feet (12 ft. by 3798 acres),



(Reproduced from Bureau of Mines R.I. 3712)

FIG. 2. Generalized cross-sections of Woodbine formation fault-line fields, Limestone, Freestone and Navarro Counties, Texas.

leaving 106,500 acre-feet of net sand in the main zone. It is thus indicated that Hill and Guthrie estimated the zone to contain only 17,000 acre-feet of shale, or 13.8 per cent. By using the sand thicknesses shown in the generalized section (Fig. 2) and the structure map, it can be shown that the shale percentage should approximate 25 per cent. Further, the thickness of 58 ft. of sand for the main zone, shown by the generalized section, may be excessive, based on interpretation of the two detail electric logs as discussed previously herein. Therefore, the shale percentage in the main zone probably is even higher than 25 per cent.

It is here estimated that the main zone contained not more than 92,600 acre feet of net sand (75 per cent of 123,500). The two upper stringers amounted to 45,500 acre-feet, giving a total of 138,100 acre-feet for the field.

The recovery from the upper stringers may be approximated at 9,100,000 bbl. by multiplying the estimated recovery of 200 bbl. per acre-foot by the sand volume. The ultimate recovery from the field will be 102,647,000 bbl., of which 9,100,000 bbl. should be attributed to the upper sands and 93,547,000 bbl. to the main sand. This latter figure is equivalent to 1010 bbl. per acre-foot from the 92,600 acre-feet of main sand estimated previously herein, and compares with 864 bbl. per acre-foot estimated by Hill and Guthrie for the fault leases, and used by Clark, Tomlinson, and Royds as main sand values for comparative purposes. These estimates are summarized in Table 1.

It is not possible to determine the average spacing for the main sand from the data of Hill and Guthrie, as completion data for all wells are not given. It was, however, greater than the spacing of 4.7 acres per well for the fault-line leases.

● **Wortham field.** The Wortham Field was discovered November 23, 1924, and development was at such a rapid rate and per-well producing rates were so high that 38 days later it had produced 888,856 bbl. of oil, an average of 23,390 bbl. per day. Initial production rates in excess of 1000 bbl. per day were common, some wells producing as much as 9000 bbl. per day. By the end of 1925, the cumulative production amounted to 16,859,981 bbl. or 72 per cent of the field's estimated ultimate recovery.

Hill and Guthrie estimate that the average ultimate recovery per acre-foot amounts to 1245 bbl. This recovery appears to be high for the main sand for two reasons: *a*, none of the recovery has been attributed to the upper sand stringers which have been proved productive; and, *b*, the original water level was estimated too high for most of the field, probably because of water coning induced by the high rates of production.

Two thin sands approximately 40 ft. and 20 ft. above the main sand were logged in many wells, and are shown in the generalized section (Fig. 2). Hill and Guthrie state: "Little consideration was given these two strata when the field was first developed," although in the majority of the wells shown in the cross-sections (Fig. 10 and 11, R.I. 3712) of their report casing was set above these sands so that they were open to the well bore.

There have been 24 wells drilled since 1940, generally along the axis of the structure. In an area of approximately 100 acres, 11 of these wells have been completed in the upper sands only. Their production ranges from 17 to 121 bbl. of oil per day. All produce from 60 to 96 per cent water, showing that also in the upper sands a water drive is present. The character of the sand is further indicated by one core analysis[5] which showed 28 per cent porosity and 1620 millidarcys

TABLE 3—Recoveries—fault-line fields.

Field	Ultimate production, bbl.	Sand, acre-feet	Recovery, bbl per acre-foot	Spacing, acres per well
Mexia[1]	93,547,000	92,600	1010	4.7
Wortham	23,500,000	20,818	1100[2]	2.1
Currie	7,000,000	7,551	927	5.8
Richland	6,500,000	5,933	1096	2.4
Powell	113,500,000	120,813	939	3.5

[1]Main Woodbine sand, only.
[2]Includes an approximate correction for recovery from upper sands.

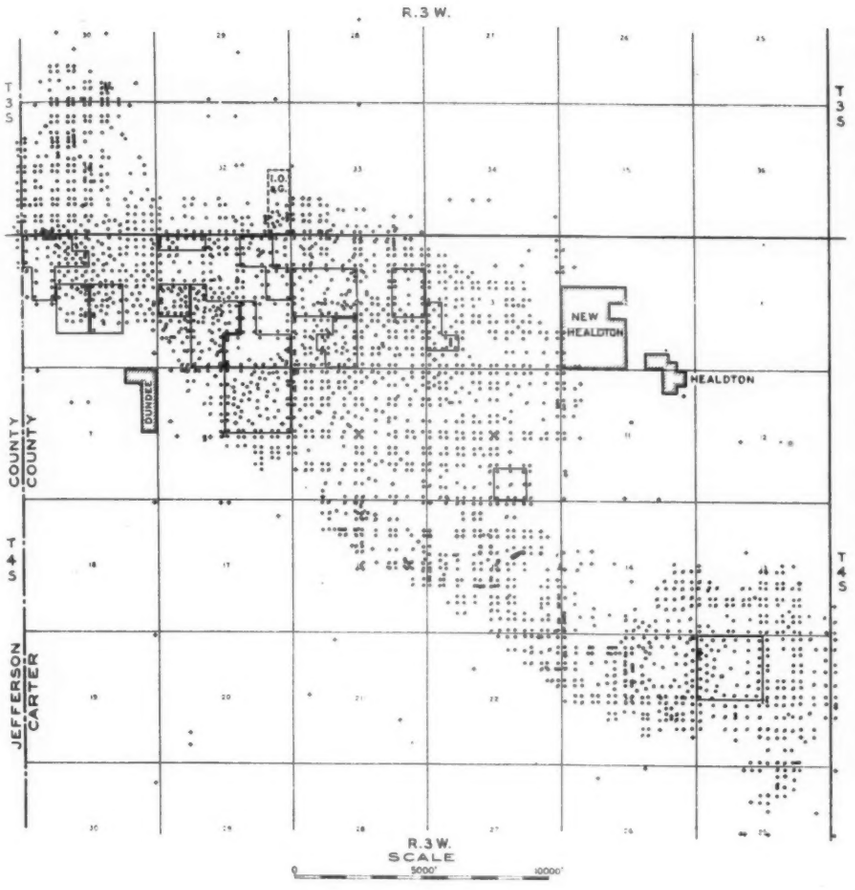


FIG. 3. Healdton field, Jefferson and Carter Counties, Oklahoma.

permiability. This one porosity from an upper thin sandstone is used by Hill and Guthrie to calculate percentage recoveries which were in turn presented by Clark, Tomlinson, and Royds.

Hill and Guthrie suggest that these sands originally may have been productive also on the flanks of the structure by the following statement: "Drilling records and cross-sections suggest (with the possible exception in an area developed by a few wells on the extreme eastern flank of the field) that the upper 50 ft. to 60 ft. of the Woodbine formation in the Wortham Field consists largely of broken sand and shale." It is presumed the eastern flank area referred to centers around tracts 1, 19, 20, 21, and 82, where the wells lie very near or beyond the productive limit (Fig. 9—R.I. 3712) for the main sand.

It is not possible with the data available to compute the recovery attributable to the upper sands. Because of their high permeability and the presence of water drive, the unit (per acre-foot) recovery should be large. The original productive areas is unknown, and the total recovery, therefore, cannot be estimated. It is evident, however, that the calculated unit recovery for the main sand should be corrected for the contribution of the upper sands.

In Table 2 are the data for all wells shown in Figs. 10 and 11 of the Hill and Guthrie report—which were completed to produce from sand below an elevation of 2540 ft. below sea level, and for which test information was available. Water levels shown on the sections were as follows (depths in feet below sea level): A—2560; B—2555; C, D, and E—2550.

The use of different levels for various parts of the reservoir is indicative of the difficulty in locating the water table. Because of the high withdrawal rates during the development period, water coned into many wells. This caused the water level to be located too high. Such appears to be the case for wells 5, 6, and 7 of Section D'-D, for which the initial rates were very high. On the same section is well No. 10, completed from 2547 ft. to 2555 ft. below sea level, which produced only 9 per cent water and sediment on February 20, 1925. From the data given in Table 2 and on the sections of the Hill and Guthrie report, there is not sufficient justification for locating the water at higher than 2555 ft. below sea level in any part of the reservoir.

TABLE 4—Recovery estimates for 15 Leases—Healdton field.

	Prior to infill drilling	After infill drilling
Productive acres	1,455	1,455
Number of wells	382	508
Spacing, acres per well	3.81	2.86
Ultimate recovery:		
Bbl. (estimated)	77,920,000	79,440,000
Calculated by square-root rule	....	89,840,000
Increased recovery:		
Bbl. (estimated)	...	1,520,000
Calculated by square-root rule	....	11,920,000
Increase per infill well (estimated)	....	12,050
Calculated by square-root rule	....	94,700

If, in the central part of the field, the original position of the water table is placed at 2555 ft. below sea level, 3900 of gross acre-feet are added to the reservoir volume. Assuming that 50 per cent of this volume is shale, 1950 acre-feet of net sand are added to 18,868 acre-feet, making a total volume of 20,818 acre-feet, so that the ultimate recovery of 23,500,000 bbl. now is equivalent to 1129 bbl. per acre-foot. If correction is made for recovery from the upper sands, it is doubtful that unit recovery from the main sand will exceed 1100 bbl., rather than 1245 bbl. per acre-foot for a spacing of 2.1 acres per well (which also includes wells completed in the upper sands only) estimated by Hill and Guthrie. The higher recovery for Wortham, as compared with Mexia and Powell, should be attributed to the better average quality of the main zone (Figs. 1 and 2) rather than to differences in spacing.

● **Currie field.** Hill and Guthrie attribute the lowest recovery of all the fault-line fields, 770 bbl. per acre-foot, to Currie. This low recovery is attributable in large part to the fact that a recognized gas cap was included when calculating the acre-feet of oil sand. Clark, Tomlinson, and Royds accept the low recovery as being due to the relatively large spacing of one well per 5.8 acres.

In Fig. 2 the generalized section for the Currie Field shows a gas zone to a depth of 2520 ft. below sea level, just above a 3-ft. shale break. This gas zone was recognized early in the life of the field. The discovery well is reported producing a large volume of gas (top of sand, 2540 ft. below sea level) in December 1921, two months after completion. The second well was completed in 1922. The record is not clear whether the well was a 4,000,000-cu.-ft. gasser on March 12, 1922, and blew in oil to the amount of 500 bbl. on March 23, 1922, or whether the well was originally completed at a very high gas-oil ratio. It seems evident that a sizeable gas cap or gas sand was encountered in the main Woodbine pay sand.

Tabulated hereinafter are wells which were shown in Figs. 15 and 16 of R.I. 3712 as logging the gas sand. An average gas-oil contact of 2522 ft. below sea level is indicated:

Operator and well		Gas-oil contact, ft. below sea level
Newblock	Bounds No. 1	2527
Homaokla	McGaw No. 3	2523
J. K. Hughes	McGaw No. 2	2517
	McGaw No. 3	2521
Average		2522

The volume of sand above 2520 ft. be-

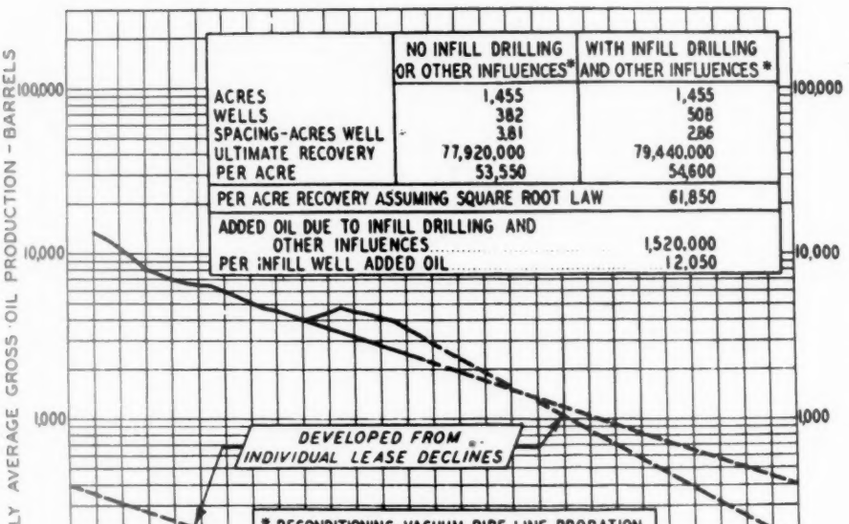

DAILY AVERAGE GROSS OIL PRODUCTION - BARRELS
100,000
10,000
1,000
100
NO INFILL DRILLING OR OTHER INFLUENCES*
WITH INFILL DRILLING AND OTHER INFLUENCES *
ACRES 1,455 1,455
WELLS 382 508
SPACING-ACRES WELL 3.81 2.86
ULTIMATE RECOVERY 77,920,000 79,440,000
PER ACRE 53,550 54,600
PER ACRE RECOVERY ASSUMING SQUARE ROOT LAW 61,850
ADDED OIL DUE TO INFILL DRILLING AND OTHER INFLUENCES 1,520,000
PER INFILL WELL ADDED OIL 12,050
DEVELOPED FROM INDIVIDUAL LEASE DECLINES
* RECONDITIONING, VACUUM, PIPE LINE, PRORATION, AND INCREASED SALE PRICE OF OIL.
1918 1922 1926 1930 1934 1938 1942 1946 1950 1954 1958 1962 1966 1970
1972 1976 1980 1984

FIG. 4. Influence of infill drilling—15 leases in Healdton pool.

low sea level is estimated at 977 acre-feet by Hill and Guthrie. The foregoing tabulation indicates that this is the minimum volume of the gas cap.

The total volume of Woodbine main zone originally above water was estimated at 9908 acre-feet. Correction must be made for the two shale breaks of 3 ft. each (Fig. 2). These would intercept the water level of 2550 ft. below sea level at lines corresponding to the 2540 and 2527 ft. below sea level contours, respectively, if they are assumed to lie at a uniform distance below the top of the contoured surface. The volumes would, therefore, approximate 3 by 350 or 1050, and 3 by 250 or 750 acre-feet, a total of 1800 ft., and compares with 1236 acre-feet estimated by Hill and Guthrie.

A further correction should be made for the shale at the base of the section (Fig. 2). However, there is some evidence (Figs. 15 and 16, R.I. 3712) that the water level may have been placed too high by Hill and Guthrie. The deduction for shale would be offset by a slight lowering of the water table and is, therefore, neglected.

Within the main sand productive area, four dry holes were drilled, two of which were Morrow sand tests (Fig. 14, R.I. 3712). No logs or other data for these wells are available and, therefore, it cannot be determined if the dry holes were due to erratic sand conditions. If this were the case, deductions in the acre-feet of productive sand given for the field should be made.

To summarize, a total oil-sand volume of 7131 acre-feet is obtained by subtracting 977 acre-feet for the gas cap and 1800 ft. for the shale zones from the 9908 acre-feet of main zone of the Woodbine at Currie obtained by Hill and Guthrie. In addition, there were 420 acre-feet of productive Morrow sand, or a total of 7551 acre-feet for the field.

The estimated ultimate production of 7,000,000 bbl. is equivalent to 927 bbl. per acre-foot. This compares with 770 bbl. per acre-foot estimated by Hill and Guthrie. Because of the presence of the large initial gas cap, the corrected Currie unit recovery is lower than that at Wortham, which has a similar sand section. The gas was rapidly dissipated, and the oil moved into the gas zone under the action of the water drive. A portion of this migratory oil is not recoverable, and a lower unit recovery, therefore, results.

● **Richland field.** The Richland field, the smallest in areal extent of the five fault-line fields, obtained the highest unit recovery, or 1383 bbl. per acre-foot, according to Hill and Guthrie. This estimate of recovery is considered excessive, because the reservoir water table was placed at too high a level.

Reference to Fig. 19 of R.I. 3712 shows the productive limit of the field as defined by the intercept of the top of the main sand with water at 2610 ft. below sea level. It is noted that seven wells, which are shown to have been initially completed as producers, lie on or beyond this limit. The cross-sections of Fig. 20 (R.I. 3712) show five wells completed at a total depth below water. These facts show that the original water level probably was below 2610 ft. below sea level.

The high recoveries obtained by edge leases is another indication that the water level was lower than 2610 ft. below sea level. Some of these edge leases are tabulated as shown at top of p. 8 (from Table 17 of R.I. 3712):

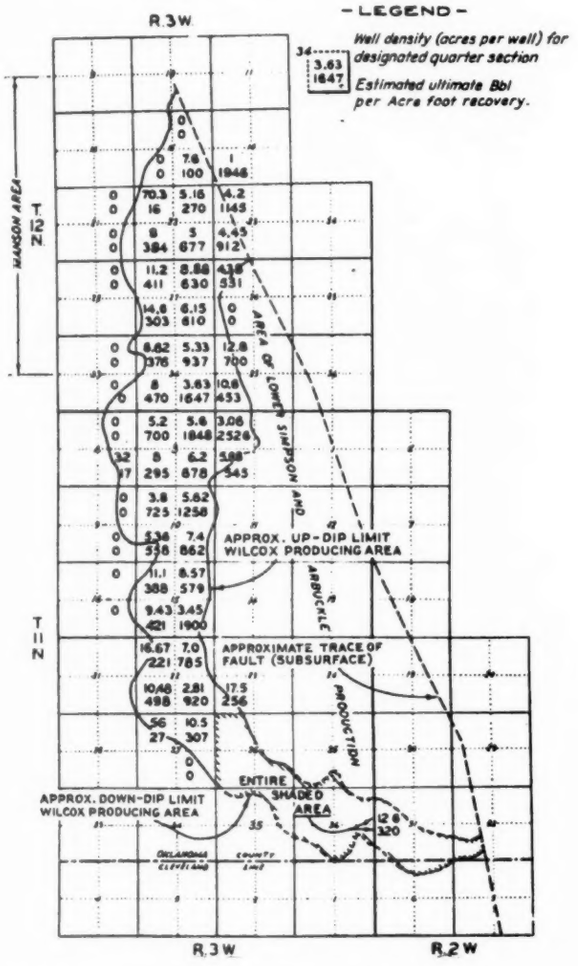


FIG. 5. Oklahoma City field—Wilcox sand zone.

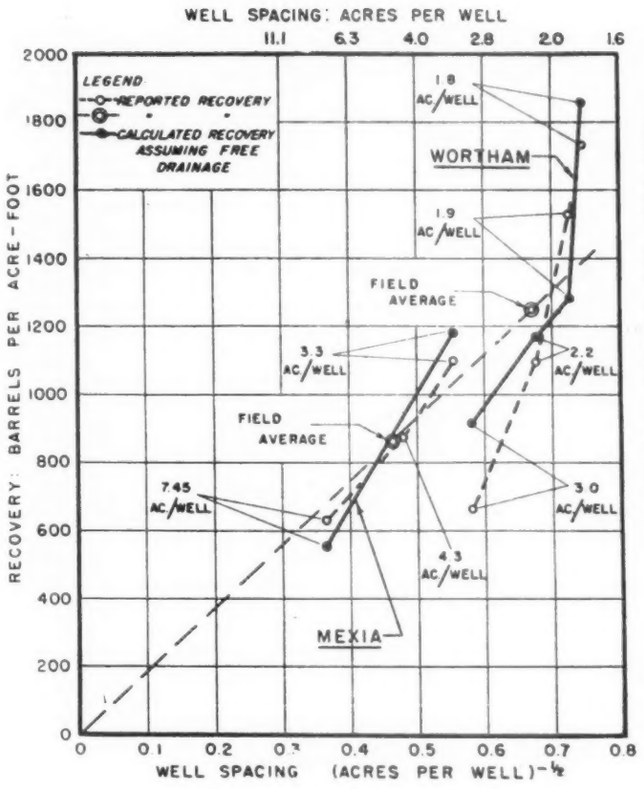


FIG. 6. Relation between well spacing and oil recovery—Mexia and Wortham fields.

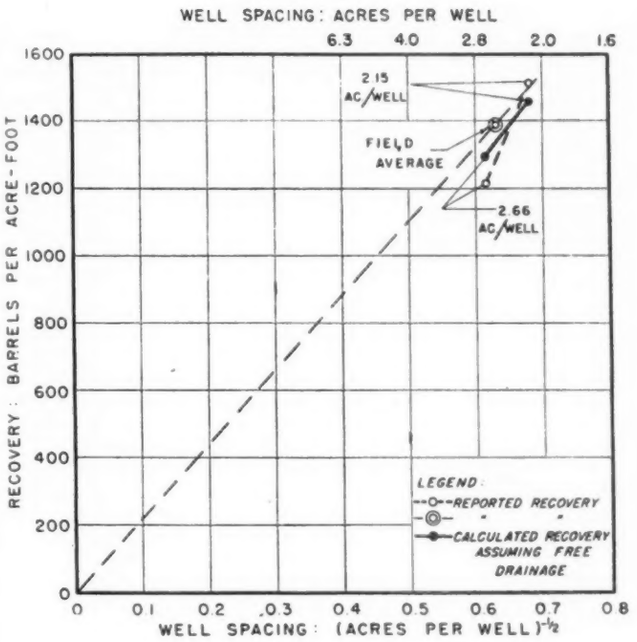


FIG. 7. Relation between well spacing and oil recovery —Richland field.

Lease symbol	Recovery, bbl.	Proved area, acres	Net sand thickness, acre-feet	Producing formation, acre-feet	Recovery, bbl. per acre-foot
B	46,120	3.28	6.7	22.0	2096
D	79,057	3.87	10.2	39.5	2001
F	100,969	2.89	6.4	18.5	5458
O	57,760	2.66	4.0	10.6	5449
P	16,893	1.28	5.0	6.4	2640
Total field	6,500,000	234.06	20.1	4,701.4	1361

These recoveries are exceedingly high for edge leases in a water-drive field. Estimating the water level at 2615 ft. below sea level (5 ft. lower) has approximately the following effect on the recovery data for the foregoing leases and the total field:

Lease symbol	Recovery, bbl.	Proved area, acres	Net sand thickness, acre-feet	Producing formation, acre-feet	Recovery, bbl. per acre-foot
B	46,120	4.25	9.6	40.8	1130
D	79,057	4.91	12.5	61.4	1288
F	100,969	5.45	7.2	39.2	2576
O	57,760	4.39	6.4	28.1	2056
P	16,893	2.32	6.6	15.3	1104
Total field	6,500,000	259.3	22.9	5,933.0	1096

The values for recovery per acre-foot for the edge leases are more reasonable, although still higher than would be anticipated from experience obtained in any water-drive field previously or subsequently developed. Reference to Fig. 19 (R.I. 3712) will show that lowering the water level to 2615 ft. below sea level places all wells which were initially productive within the productive area.

A reduction from 1383 bbl. to at least 1096 bbl. per acre-foot recovery from the total field is fully justified, and makes the recovery from this field approximately the same as that for Wortham. However, it must be concluded that the data for this field are not sufficiently accurate to form the basis for a mathematical formula relating recovery to well spacing.

● **Powell field.** The Powell field is more complex in some features than the fields previously discussed. It has a greater productive closure (190 ft.), and there is present a "big pay" at the base of the section in wells which found the top of the main sand above approximately 2435 ft. below sea level. The main sand zone is similar to the Mexia section, but has numerous sand stringers at the base and is, therefore, better developed. The 12.5-per-cent shale figure given as the average for the Powell Field looks low on the basis of the columnar section (Fig. 2, R.I. 3712), and the structure map. This is probably offset by not including the thin sand above the main sand in the total sand volume.

Use of a different water table in the north end of the field (2610 ft. below sea level) indicates that a separate closure should be made around the area of the discovery well (Fig. 23, R.I. 3712).

The recovery for the Powell Field, 939 bbl. per acre-foot, appears reasonable, and is comparable with the corrected estimated recovery from Mexia, which field has a similar sand section.

● **Summary—fault-line fields.** Hill and Guthrie concluded their report with the following paragraphs:

"The relatively close spacing of wells in the Mexia-Powell fault-line fields, ranging from a maximum density of 1 well to 2.2 acres in the Wortham field to a minimum density of 1 well to 5.8 acres in the Currie field, is indicative of the conception held by many operators during the early 1920's that, to recover a high percentage of oil from reservoir sandstones, wells should be spaced closely. Today the fallacy of extremely close spacing of wells, both from the economic and recovery viewpoints, is widely accepted, and many engineers and operators now are of the opinion that ultimate recovery in the fault-line fields was not increased measurably by drilling a large number of wells, and that about as much oil would have been recovered at a considerably lower cost of development and operation if fewer wells had been drilled in the fault-line fields.

"Obviously, an oil field cannot be developed and exploited twice—once closely spaced and again with the wells spaced farther apart — to determine which method of development will yield best results. It is appreciated, also, that no two fields are alike in all their reservoir characteristics, regardless of their geographical proximity or how closely they seem to resemble one another in all measurable properties."

A critical examination of the data presented in R.I. 3712 indicates that the fault-line fields produced between 900 bbl. and 1100 bbl. per acre-foot from the main Woodbine sand. There is considerable doubt as to the accuracy of the recovery figures because the sand volumes are not precisely known. The lack of any core data, except in an upper sand at Wortham, allows no reasonably accurate estimation of percentage recoveries.

Table 3 summarizes the recoveries estimated herein for each of the fields, and shows also the approximate surface spacing as given by Hill and Guthrie. There appears to be no relation between recoveries and approximate spacings.

● **Intrafield data.** Clark, Tomlinson, and Royds conclude from their review of the data for the fault-line fields: "The conclusive demonstration furnished by these data from separate fields, that well spacing, even with densities below 6 acres per well, does affect recoveries in accordance with a definite mathematical relationship, makes a huge volume of supporting evidence based on different spacings in the same field admissible."

The pitfalls of such logic are obvious, and have been adequately discussed by Muskat.[8] Further, an analysis by Muskat of the spacing problem in dissolved-gas-driven fields shows that the ultimate recovery should not materially depend on the number of wells drilled. Although application of the numerical results of the investigation cannot be made, the conclusions drawn are believed to be qualitatively significant. The line of reasoning shows that proper well density is mainly determined by economics of producing sufficient oil to meet demand and to yield a maximum ultimate earning.

In our opinion the data from the Texas fault-line fields referred to are not conclusive, and certainly the subsurface data available on these old fields are not sufficiently accurate for mathematical analysis of the type presented by Clark, Tomlinson, and Royds for interfield studies. Therefore, their conclusion that these interfield data allow the use of intrafield data as supporting evidence is open to question.

The intrafield data given by Clark et al. are reviewed in part in the following to show the lack of mathematical relationship proposed by Clark, Tomlinson, and Royds.

● **Lucien field.** The Lucien Field in Noble County, Oklahoma, may be considered as consisting of 2 parts; the main structure which was developed with a spacing of 40 acres per well under unitized operation, and a south extension largely developed on a 10-acre, spacing pattern.[4] Both areas produce from the First and Second "Wilcox" sands. Production from the First and Second was not segregated by Clark et al.

Whereas Clark, Tomlinson, and Royds state that the two sands are "practically identical in character," reservoir pressure and other data indicate they are not. As of July 1939, pressures measured in the Second Wilcox were 1200 lb. per sq. in. compared with 200 lb. per sq. in. in the First. In the north (unitized) end of the field, Second Wilcox wells currently have a producing capacity which is on the average four times greater than those of the First Wilcox.

It has not been possible to define the portions of the Wilcox section which are productive. Only total sand thicknesses, not "pay" thicknesses, are available. Considered on the gross-thickness basis, however, recoveries in the unitized area as of January 1, 1943 (the date of the Clark, et al. estimate), were 88 bbl. per acre-foot from the First, and 161 bbl. per acre-foot from the Second.

The average thickness of the First Wilcox in the area of 40-acre spacing is 45 ft., compared with 25 ft. in the area of 10-acre spacing. The failure of Clark, Tomlinson, and Royds to separate the two horizons results in averaging into the one area twice the amount of poor quality First Wilcox than in the other. No comparison of the relative recoveries for 40-acre and 10-acre spacing is possible on this basis.

● **Healdton field.** Data for the Ideal Oil and Gas Company Scroggins Lease (approximately 26 acres) of the Healdton Field are presented by Clark, Tomlinson, and Royds to show that additional drilling late in the productive life of the lease (infill drilling) resulted in

FIG. 8. Relation between well spacing and oil recovery —Oklahoma City field (total Wilcox zone).

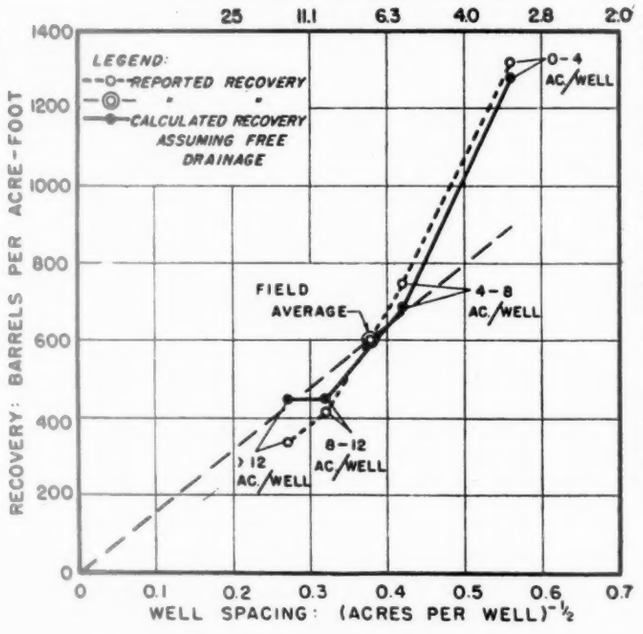
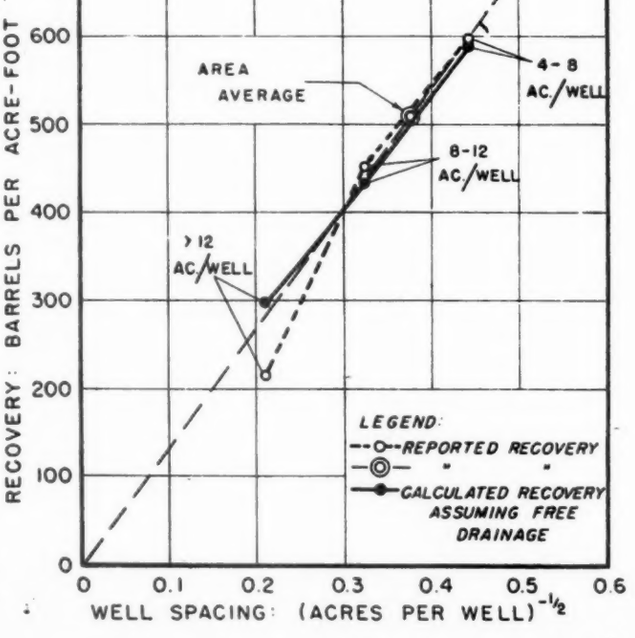


FIG. 9. Relation between well spacing and oil recovery —Oklahoma City field (Mansion area).



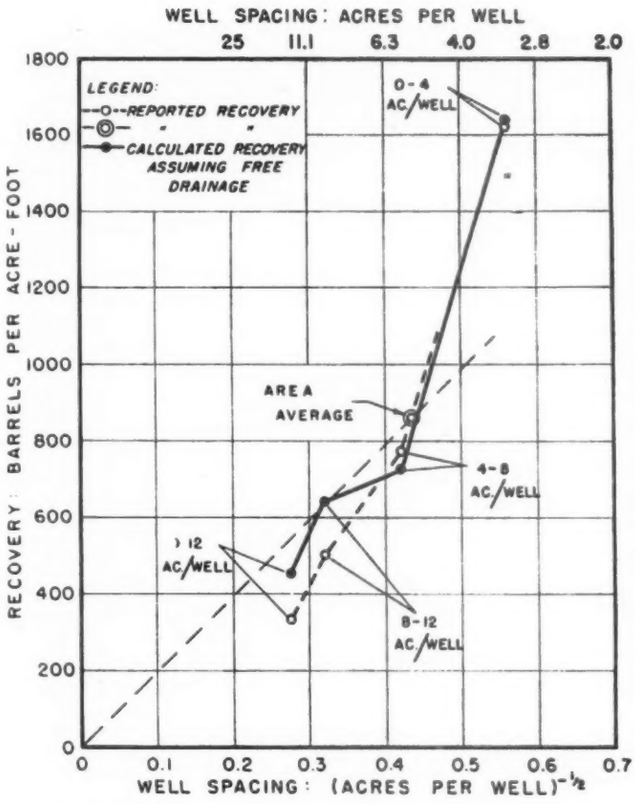


FIG. 10. Relation between well spacing and oil recovery —Oklahoma City field (updip quarter sections).

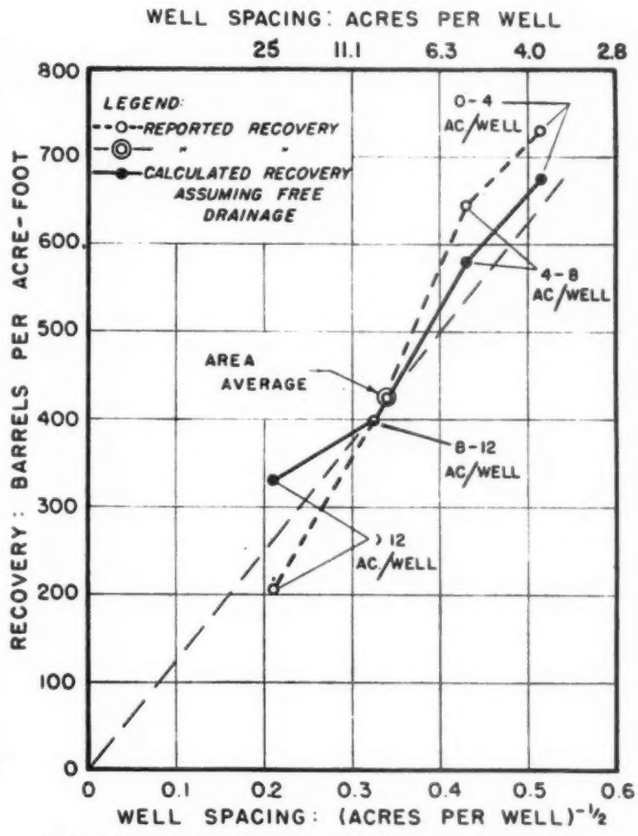


FIG. 11. Relation between well spacing and oil recovery — Oklahoma City field (downdip quarter sections).

an increase in recovery which was in accordance with the square-root rule. It is of interest to note that the northern productive limit of this lease has never been defined by drilling, and the actual acreage being drained is unknown (Fig. 3).

A more complete and detailed analysis of the results of infill drilling and other influences in this field has been made, and a summary of these results is given in Table 4 and Fig. 4. This summary presents an analysis of 15 leases (Fig. 3) in this pool—which comprise 1455 acres. Separate decline curves were prepared for each lease, and these separate decline curves were then added to give the composite result shown. The net result of this analysis shows that an additional 1,520,000 bbl. of oil have been recovered. This oil is the result not only of infill drilling, but also because of the reconditioning of wells, which was stimulated by an increase in the sale price of oil, repressuring, and the extensive application of vacuum. All these went into effect at about the same time, and all have made some definite contribution to the results noted. On the basis of the added wells drilled, this recovery amounts to but 12,000 bbl. per infill well. It is to be noted that the added recovery falls far short of the expectancy of 94,700 bbl. per well based on the square-root rule, even if all of the additional oil is credited to infill drilling. When it is considered that this added oil must be divided among all the effects set out previously herein, it is clear that the contribution of the infill drilling alone was indeed small, and something less than attractive financially.

The geology of Healdton is complicated and the sands are lenticular. Strictly speaking, each reservoir should be analyzed separately to prevent confusion caused by broad application of the term "spacing." Results of infill drilling in some isolated areas were better than average due to the tapping of productive lenses not previously penetrated. However, risks must be based on average conditions, which at Healdton indicate that infill drilling alone results in economic loss.

● **Oklahoma City field.** The Oklahoma City field is notorious for the large volumes of oil which have migrated from one area to another. At least 50,000,000 bbl. migrated from the Mansion area, prior to its development, into the portion of the field to the south. Movement of water into the reservoir from the west moved oil from under downdip acreage. Gravity drainage has been responsible for extensive downdip movement of oil. Recovery by a given well was primarily dependent on the allowable permitted the well. During the period of proration, allowables were based on potentials, which were often magnified by various artificial lifts in large-size casings, factors other than well spacing, and pay thickness; and densely drilled areas wantonly drained areas less densely drilled.

The Mansion area was developed during and after 1935. The first production from elsewhere in the Wilcox was in March, 1930, and by January, 1935, the average reservoir pressure had declined from the original 2686 lb. per sq. in. to 430 lb. per sq. in., absolute. An estimate by Katz[9] indicates that 86,000,000 bbl. of oil have migrated from the Mansion area because of earlier development of, and high rate of, production from other areas.

The average quality of the Wilcox sand varies both vertically and laterally. The top 40 ft. or so of the section is of poorer quality than that below. This is shown by core analyses in Table 7 of the Katz paper, and by the following excerpt from a statement referring to this upper sand: . . . "more nearly represents the 'tight' sand of stratum 'A' in Fig. 7 than the 'loose' sand of stratum 'B' in the reservoir." The Fig. 7 referred to shows the division of the Wilcox into strata, and further demonstrates the better quality of "B" by showing that the encroachment of edge water was more rapid than in "A." The poorer quality of "A" results in the downdip (west-edge) leases having a section of inferior quality compared with those updip.

The part of the field south of Section 22-11-3 (Fig. 5) contains sand of poorer quality than the main body of the reservoir. This fact is borne out by the observation that the ultimate recovery per well

TABLE 5—Oklahoma City field—total Wilcox zone.

Spacing, acres per well	0–4	4–8	8–12	Over 12	Miscellaneous and undrilled	Total
1. Number of wells	215	358	192	134	5	904
2. Effective acres	709	2,007	1,784	1,622	621	6,743
3. Acres per well (spacing)	3.3	5.6	10.4	13.1	....	7.45
4. Acre-feet "pay"	93,983	259,180	240,934	166,586	39,512	836,195
5. Estimated ultimate recovery (1,000 bbl.)	123,490	221,191	102,845	53,868	....	501,394
6. Observed recovery, bbl. per acre-foot	1,314	749	427	324	....	600
7. Average recovery, bbl. per well	....	....	....	....	....	554,600
8. Barrels per well times number of wells (1,000 bbl.)	119,245	198,558	106,489	74,320	....	....
9. Calculated recovery, bbl. per acre-foot (free drainage assumed)	1,269	673	442	446	....	600

in this area is only 440,000 bbl. per well, compared with 660,000 bbl. per well in the more densely drilled area to the north, although the sand thicknesses are approximately equal. In addition, considerable gas was encountered in some of the Wilcox in the southern end. This gas limited the space occupied by oil.

The map (Fig. 5) is taken from the Clark et al. paper. The values established for recovery with wide spacing are wholly dominated by the shaded area south of Section 2-11-3, and the acreage along the west edge of the field. It has been pointed out that the sand in these areas is of unquestionably poorer quality than in the remainder of the field. Furthermore, it is significant that about 20 per cent of the reservoir volume of the Wilcox sand was invaded by water encroaching from the west, and this movement was more pronounced in the northern part of the field. This water encroachment discouraged drilling along the west edge, and moved oil to structurally higher, more densely drilled locations.

It is noted (Fig. 4) that certain quarter-sections have recovered from 1½ to more than 2 times the original oil in place, which can be calculated from the data of Katz[9] to be 1200 bbl. per acre-foot. Examples of this are to be found in the northwest quarter of Section 2-11N-3W, the northeast quarter of Section 3-11N-3W, the southeast quarter of Section 15-11N-3W, and the southeast quarter of Section 34-12N-3W; a number of other cases of abnormally high recoveries can also be seen. These tracts were not only more densely drilled, but those tracts along the east flank of the pool were drilled into the thinnest section of the Wilcox sand. The Oklahoma City field was prorated on the basis of well potential. Furthermore, the areas of high potential were more densely drilled because the high allowables made such drilling economic. As the proration formula did not consider the thickness of the section, wells were produced at rates out of proportion to recoverable oil attributable to the well, resulting in drainage of oil from other tracts. Despite this fact, the data from these tracts were considered in establishing the values of recovery and spacing to be used in support of the square-root assumption.

The Oklahoma City field is an excellent example of a field wholly unsuited for a study of well spacing. The differences in recovery are due to drainage of one area by wells in another. The effect of spacing differences upon recovery in the Oklahoma City field is marked by large-scale migration of oil in the reservoir.

● **Spacing—recovery relationships.** According to Cutler's rule and the proposal of Clark, Tomlinson, and Royds, if the reciprocal of the square root of the spacing expressed as acres per well is plotted on one coordinate and the unit recovery in barrels per acre-foot on the other, a straight line from the origin can be drawn through the points. In this manner, the graphs of Figs. 3, 4, 7, and 8 of the Clark et al. paper were constructed. Deviation of the points from the straight-line curves were discussed, and it was pointed out that the deviations were toward a steeper slope, indicating that "the more widely spaced [wells were] . . . penalized to a greater degree than would be expected." Comparison of graphs for the Oklahoma City field with those for the fault-line fields indicated that proration tends to "aggravate that effect." No explanation is given for the fact that some of the densest drilled areas show recoveries greater than the amount of oil that could possibly have been present in the pore space.

If a free drainage condition in the reservoir is assumed, so that each well is completed simultaneously and produces the same amount of oil, a theoretical recovery per acre-foot from areas of different spacing can be calculated, based on a knowledge of the total recovery from all wells. This condition is equivalent to assuming that there existed a full interference between wells with an equal division of the recovery of oil among all the wells (without advantage of early completion or structural position), and is the "straws in a glass" concept mentioned by Clark et al. Calculations have been made for the Oklahoma City and fault-line fields, and the results are compared with actual recoveries in Figs. 6, 7, 8, 9, 10, and 11. The calculated curve based on the square-root rule (straight line through origin) also is shown. Table 5 shows the calculations for the Oklahoma City field using the free-drainage assumption.

Recoveries per acre-foot and spacings used in the calculations were those of Clark, Tomlinson, and Royds to facilitate comparison, although the values are not acceptable as discussed previously. It is noted that a better general agreement between calculated and reported recovery is obtained by assuming equal per-well recovery than by use of the square-root rule.

It is concluded that the intrafield relationships between spacing and recovery presented by Clark, Tomlinson, and Royds are due to drainage of oil by densely drilled areas from those less densely drilled. The data are not pertinent to the spacing problem for a given field, but serve only to illustrate the inequitable recoveries which may result from the methods used to develop and produce some fields.

● **Conclusions.** 1. The unit recovery figures calculated by Hill and Guthrie for the fault-line fields are not based on accurate subsurface or reservoir information. When obvious corrections in the net sand volumes are made, it is indicated that recovery is practically independent of spacing. Therefore, the Clark, Tomlinson, and Royds formula, which depended in great part on this data, has no basis which would allow its acceptance.

2. Data for recoveries from areas within a reservoir (intrafield) should not be used to substantiate a formula proposed to relate total recovery from a reservoir to the spacing used to develop it.

3. Intrafield spacing-recovery relationships exist because of drainage from less densely drilled areas to those more densely drilled. In many cases an assumption of equal recovery per well enables a calculation of this drainage, which agrees more closely with fact than that calculated by the Cutler (square-root) rule.

Much progress has been made by the petroleum industry in the past decade toward an understanding of the principles governing reservoir performance, and in the intelligent application of these principles to the problem of "spacing." The industry should continue this progressive trend. Well locations (spacing) should be based on the best contemporary knowledge of reservoir behavior, and not on the basis of empirical formulas which were proposed in the early days of the industry.

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Trends in Drilling Costs in California*

By **RALPH W. MARSHALL** and **ROBERT C. SHARP**, Drilling and Exploration Company

● **Introduction.** The subject of drilling costs is one that should be of vital interest to everyone connected with the petroleum industry for in the final analysis the drilling of an oil well is fundamentally a problem in economics. This is true whether the well be 1000 ft. deep or 15,000 ft. deep, and whether it is drilled in California or South America. Based upon past experience, it is possible to estimate, though perhaps with not too much accuracy, that it will cost so many dollars to drill a well, and that this well, if productive, will return so many dollars. Any change in drilling costs obviously affects this balance, as is indicated by the fact that many wells are being drilled today that would not have been economic to drill a few years ago. Likewise, with the introduction of more efficient equipment and better drilling methods, there will be wells drilled in the future that are not economical today.

With the thought in mind of the importance of drilling costs, let us examine the trends in drilling costs in California during the last nine years. We should like to make clear at this point that due to the difficulty in assembling the required information from the entire industry, and due to the limited time allocated to this study, this paper is being presented as a progress report and not as a final and conclusive summary. It is suggested that this study be continued and a further report be presented at some future meeting.

Also, we should like to point out that all the companies that have supplied information on their drilling costs have requested that no specific reference be made to their figures, but that they be included with the general overall totals.

● **Average number of rig days—wells of all depths.** Exclusive of the cost of site preparation, casing, and production equipment, there are two general factors that go to make up the cost of drilling an oil well. Number one is the operating *days*, and number two is the operating *cost* per day.

First, let us look at the overall average of the number of operating days. Fig. 1 represents the average of 1187 California wells varying in depth from approximately 2000 ft. to 13,000 ft. and includes all active areas during the nine years from 1936 to 1945. The 1187 wells represented do not include wildcat or exploratory wells, but only those drilled in proved territory. Further, the days shown are total rig days, beginning with the first day of rigging up and ending with the day that the oil is turned to the tanks. You will note that the average number of rig days has decreased from 126 in 1936 to 82 in 1945. You will also note that the number of days dropped very rapidly from 1936 to 1941, due primarily to more efficient drilling equipment and better drilling methods. From 1941, the first war year, the curve rises sharply to 1944. This rise was primarily due to the shortage of equipment, new and inefficient labor, and the other unusual factors caused by the dislocation of war. It is encouraging to note that the number of total rig days has gone down from 96 in 1944 to 82 in 1945. No doubt this trend will continue as more modern and efficient equipment becomes available and rotary crews return to their former high standards.

● **Average operating costs—wells of all depths.** Next, let us see what has happened to operating costs during this same nine-year period from 1936 to 1945. Fig. 2 is an average of 674 California wells of all depths and in all areas. Again, no wildcat or exploratory wells are included. Operating cost as shown on the curves consists of labor, repairs and supplies, depreciation of capital equipment, tool rental including bits, mud costs, over-

FIG. 1

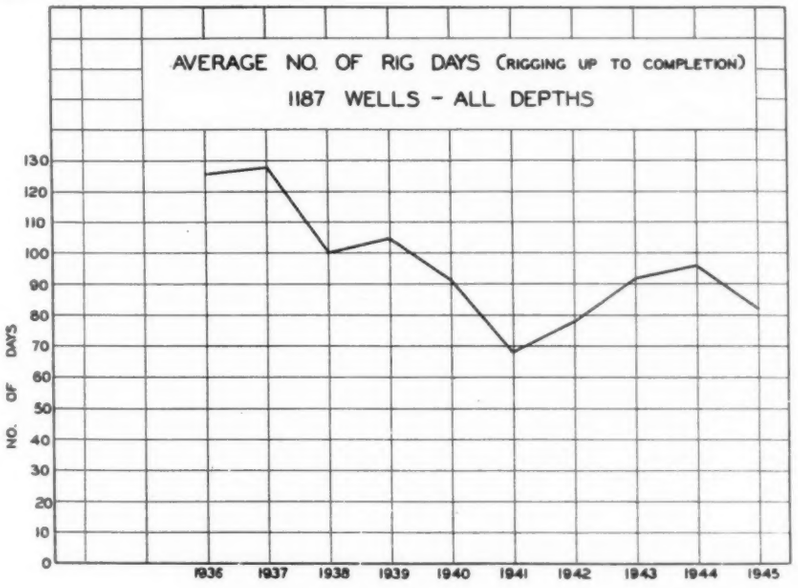
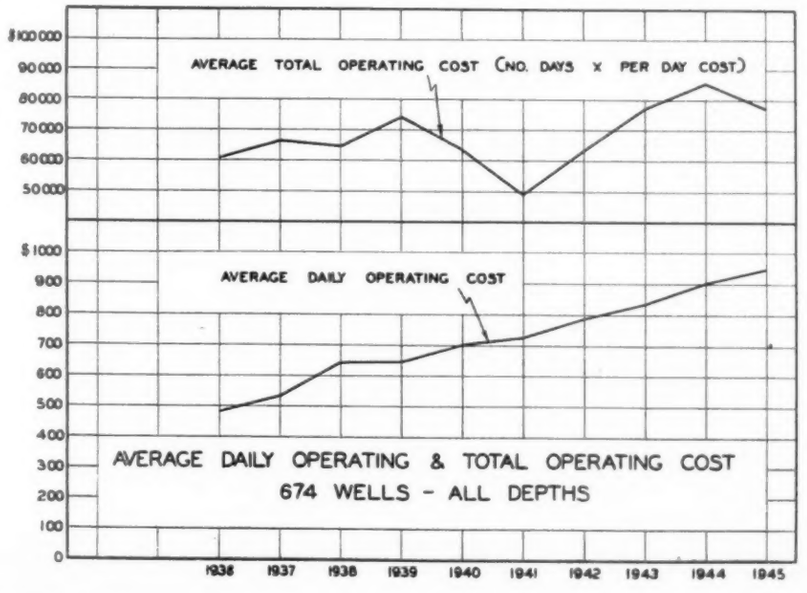


FIG. 2



*Presented before American Petroleum Institute Pacific Coast District Division of Production, Los Angeles, April 11, 1946.

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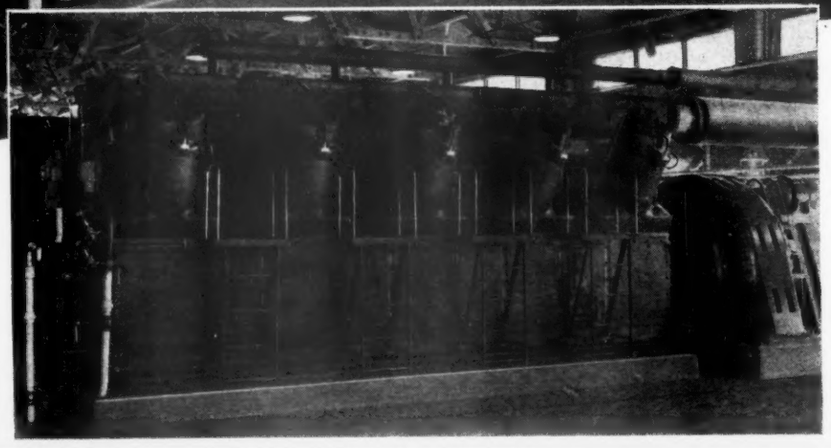

Above: Nine of eighteen Cooper-Bessemer GMV gas engines driving generators at the Phillips Plains Plant, Borger, Texas. Each is a 10-cylinder, V-type, 1000 hp unit direct-connected to an 875 KVA flywheel-type generator as shown at right.

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FIG. 3

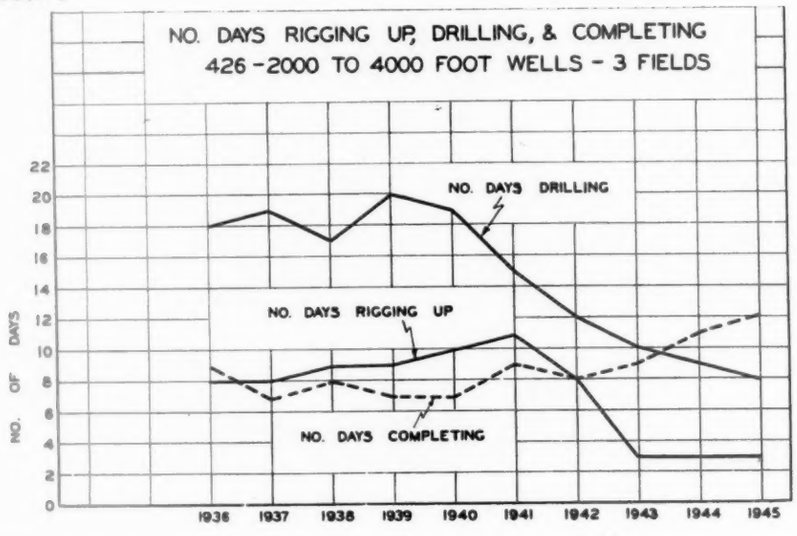


FIG. 4

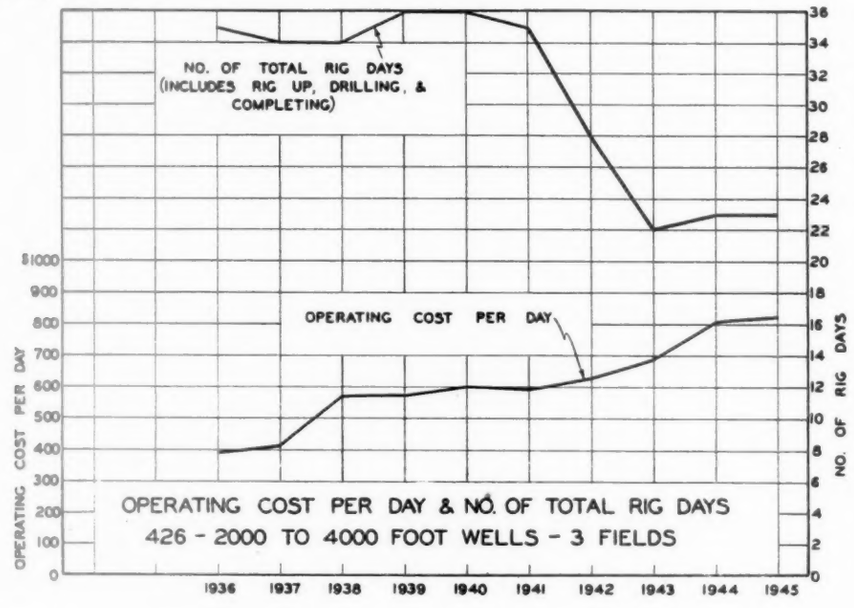
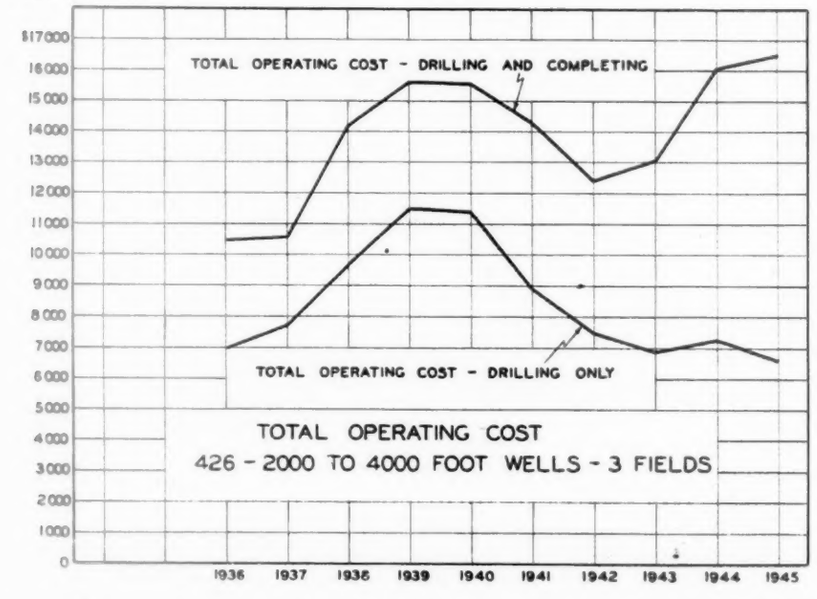


FIG. 5



head, and all other charges that go to make up the total cost of operating a drilling rig. This does not include the cost of roads, sumps, derrick, casing, or any permanent well equipment.

You will note from the lower curve on Fig. 2 that the average daily operating cost has risen from a total of $480 per day in 1936 to a total of $940 per day in 1945, an increase of almost 100 per cent. It is also interesting to note that this rise has been almost constant, averaging approximately 10 per cent each year. Some of the factors that have contributed to this steady increase are quite obvious, such as the increase in the cost of labor, materials, and services. Equally as important, though not so obvious, are the two items of depreciation of capital equipment and the operating cost of this equipment. Ten years ago a complete drilling rig, then considered adequate for drilling to 10,000 ft., could be purchased for some $90,000. Today, a modern 10,000-ft. rig, complete with alloy steel drill pipe, will cost between $150,000 and $200,000 or about twice the cost ten years ago. The additional depreciation charge against this more expensive equipment and the higher operating cost due to the additional work being done per day, are two of the important factors contributing to the higher operating costs. These two factors have, however, led to an overall saving since the introduction of modern and more efficient equipment has led to a reduction in the number of operating days. In other words, we are now *spending* more per day, but we are also doing more *work* per day.

Referring again to Fig. 2, the upper curve shows the trend in *total* operating cost, which is the operating cost per day multiplied by the number of operating days. It may be seen that from 1936 to 1939, this total cost increased from $61,000 to $74,000, then dropped to a low of $49,000 in 1941. From 1936 to 1941, the five-year period just previous to the war, *daily* operating costs increased 50 per cent, but the *total* operating costs actually decreased approximately 20 per cent. This was due to the fact that the reduction in number of operating *days* more than offset the increase in per day costs. From 1941 to 1944, due to many factors occasioned by the war, the total operating cost rose from $49,000 to $85,000, or approximately 75 per cent. It is encouraging to note that the figure dropped to $77,000 in 1945, during a year in which we were still confronted not only with increasing costs, but also with continued material shortages and labor difficulties. As more and better material becomes available, and as the labor situation returns to normal, we may expect this downward trend to continue.

● **Analysis of days and operating costs —shallow wells.** So far we have examined the general trends for wells of all depths. Now let us consider wells of a specific depth. We have compiled figures on 426 wells drilled in California from 1936 to 1945 and varying in depth from 2000 ft. to 4000 ft. These wells were drilled in three different fields. Fig. 3.

FIG. 6

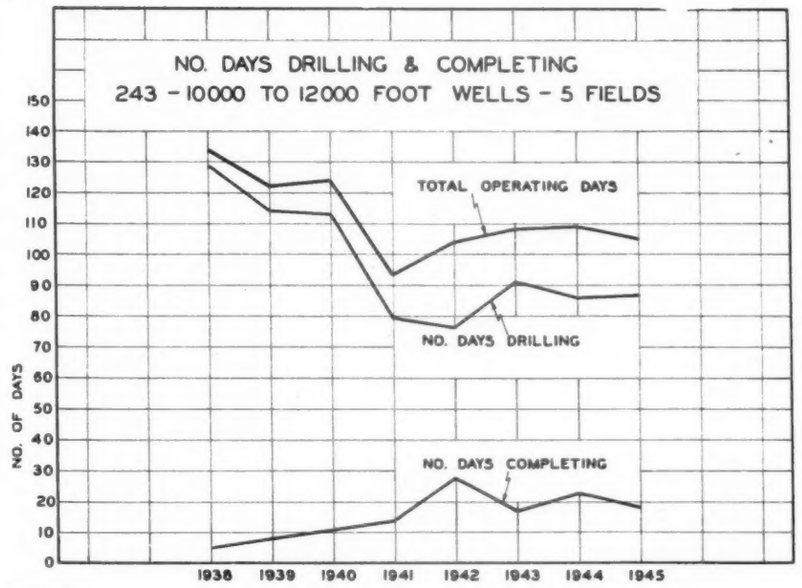


FIG. 7

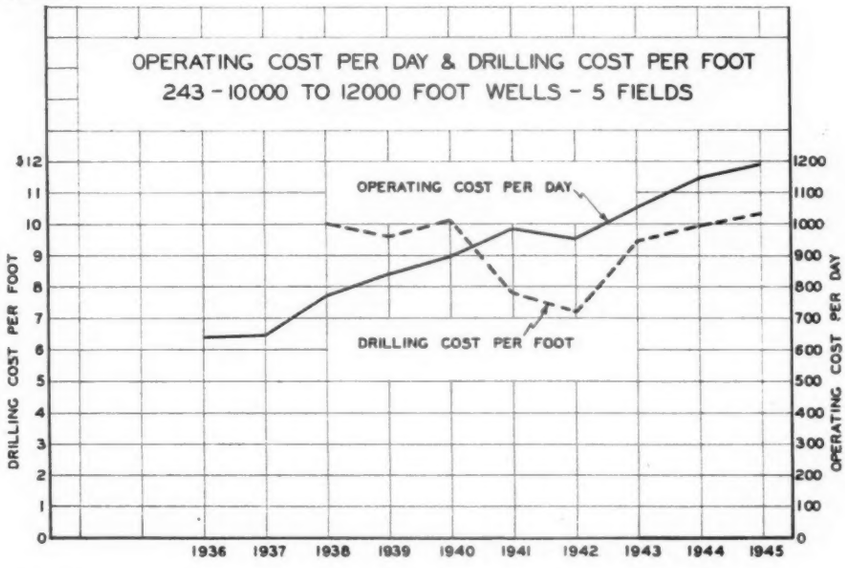
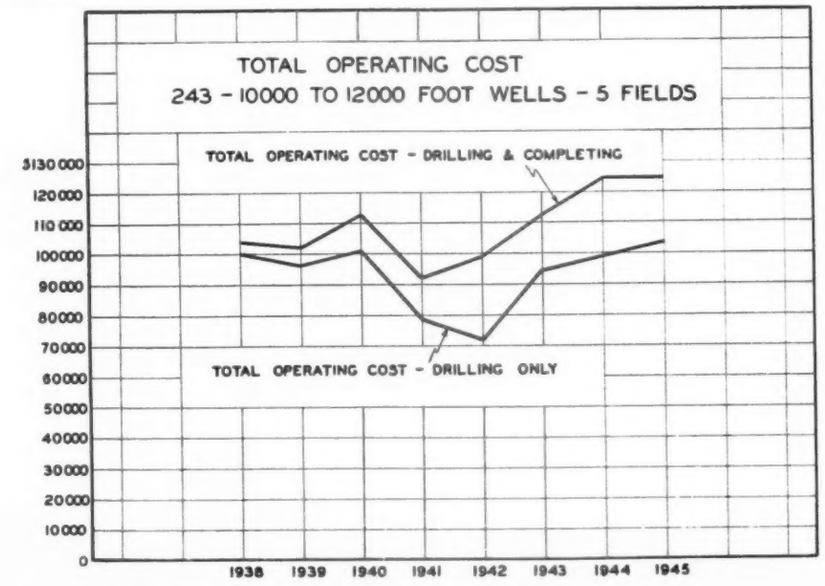


FIG. 8



showing the total operating days, indicates that the number of days rigging up and the number of days drilling, have decreased to a very marked degree. However, the number of days spent in completion operations has risen during the same period. In fact, in 1945 these shallow wells were *drilled* in an average of only eight days while twelve days were spent in completion work. Probably the biggest factor that has contributed to both the reduction in days rigging up and days drilling has been the wider use of improved and more efficient drilling equipment in the form of portable derricks and modern power rigs.

Fig. 4 indicates that operating costs have increased from approximately $400 per day to more than $800 per day, but that the total rig days, in spite of the increase in completion time, has decreased from an average of approximately 35 days to an average of 23 days.

Both of these factors are reflected in Fig. 5 where we see that the operating costs of drilling *only* were approximately $7000 in 1945, the same approximate total as in 1936, even though per day costs increased more than 100 per cent. During this same period from 1936 to 1945, the *total* operating costs increased from $10,500 to more than $16,000. In other words, in wells of this depth, from 2000 ft. to 4000 ft., more than half of the total operating costs are due to the time spent in completion operations.

● **Analysis of days and operating costs —deep wells.** We have briefly examined the trends in drilling costs in 2000 to 4000-ft. wells. Now let us move to the other end of the scale and consider wells from 10,000 to 12,000 ft. The data received consist of information on 243 wells in this depth range from five different proved fields.

Fig. 6 indicates, as in the case of the shallow wells, that the *total* operating days have decreased in the last eight years, and that this is in spite of an increase in the number of days spent in completion work.

In other words, the *decrease* in the number of days actually drilling has more than offset the *increase* in the number of days of completion operations. In addition to the introduction of modern heavy equipment, perhaps the most important factor contributing to the decrease in drilling days on these deep wells has been the improved technical supervision resulting in better mud control, fewer fishing jobs, and more efficient operation of the drilling string.

Fig. 7 shows that the operating cost per day of the equipment used on our deepest wells has increased from $620 per day to almost $1200 per day—again almost a two-fold increase. Due to the reduction in the number of actual drilling days, the cost per foot of hole drilled has shown no increase. Indeed, during the years 1941 and 1942 the cost per foot actually decreased. As we again obtain adequate equipment and more experienced and competent labor, we may assume that the drilling cost per foot will continue to show a downward trend. Considering *total* operating costs of

FIG. 9

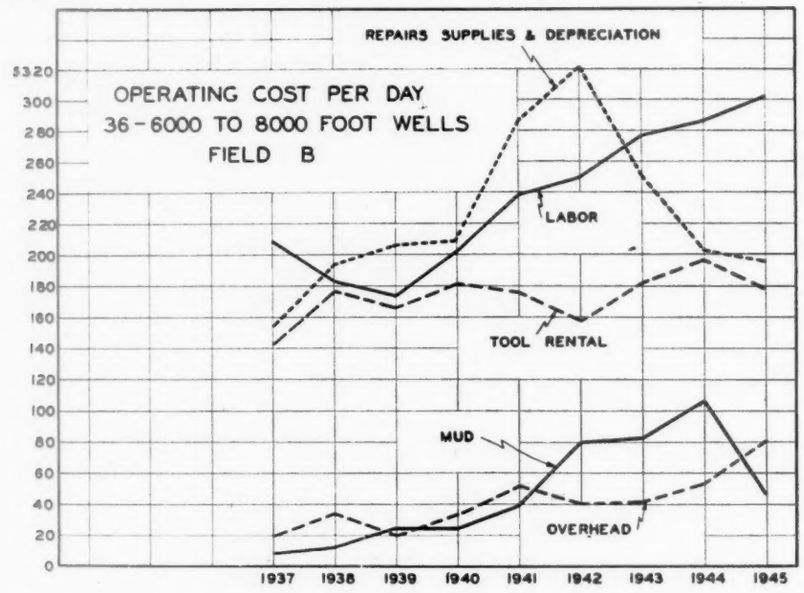


FIG. 10. Operating Costs Per Day—1937 and 1945—Thirty-six 6000 to 8000-ft. Wells, Field B

	1937		1945	
	Amt.	Per Cent	Amt.	Per Cent
Labor cost	$209.	36	$303.	36
Repairs, supplies and depreciation	155.	27	148.	18
Tool rental	142.	25	179.	21
Mud costs	8.	1	47.	6
Overhead	20.	3	81.	10
Trucking	28.	5	50.	6
Miscellaneous other	16.	3	26.	3
Total	578.	100	834.	100

these deep wells, which of course includes the cost of completion work, we see that overall operating cost has increased from $104,000 in 1938 to $125,000 in 1945. (Fig. 8).

Comparing only drilling operations, *exclusive* of completion work, we find that the average cost to drill a deep well was about the same in 1945 as it was in 1938. If the production engineers of the industry can devise methods of reducing the number of days required to complete these deep wells, then the *total* operating costs will also be reduced. Much of this completion work is in the experimental stage, as for example, the use of special muds, and as we gain more experience in these fields, the time spent in the application of these methods may be expected to decrease.

● **Detailed analysis of costs—7000-ft. wells.** So far we have considered operating costs and drilling time in rather general terms. It may be of interest to break down operating costs and see what has happened during the last nine years to some of the principal items which go to make up the total. Fig. 9 is a summary of the operating costs per day for 36 wells drilled from 1937 to 1945 and all located in one proved field. These wells vary in depth from 6000 to 8000 ft. It should be borne in mind that these figures are for only one field and, there being many variables in the cost of drilling a well from field to field and from well to well within a single field, it may be misleading to draw a general conclusion from these figures.

We note that labor costs have increased approximately 70 per cent from 1939 to 1945. Overhead has increased approximately 200 per cent. Tool rental has remained almost the same. Mud costs increased sharply to 1944. Repairs, supplies, and depreciation increased 100 per cent from 1937 to 1942, but have decreased sharply since then. Since depreciation of capital equipment is perhaps the biggest percentage of this item, and since this depreciation is primarily an individual company tax matter, this marked decrease in this item is not common to the entire industry.

The breakdown of operating costs may be further analyzed in the form of a table as shown in Fig. 10, which compares the various items of operating cost in the two years 1937 and 1945. It is interesting to note that labor costs have remained constant at 36 per cent of the total. Repairs, supplies, and depreciation have decreased from 25 per cent to 21 per cent, mud costs increased from 1 per cent to 6 per cent, and overhead showed the most marked increase from $20 per day or 3 per cent, to $81 per day or 10 per cent. This increase in overhead is no doubt largely due to increased supervision, which, in turn, has resulted in more efficient operations.

Fig. 11 shows the three principal items that go to make up the *total* overall costs of these 36 wells. The cost of site preparation, including roads, sumps, and rigging up, decreased 50 per cent in the years just previous to the war, but has now risen again to approximately the same 1936 figure of $25,000. The total cost of the derrick, casing, and production equipment has decreased from an original figure of $48,000 to approximately $26,000, due largely to a simplification of the casing program.

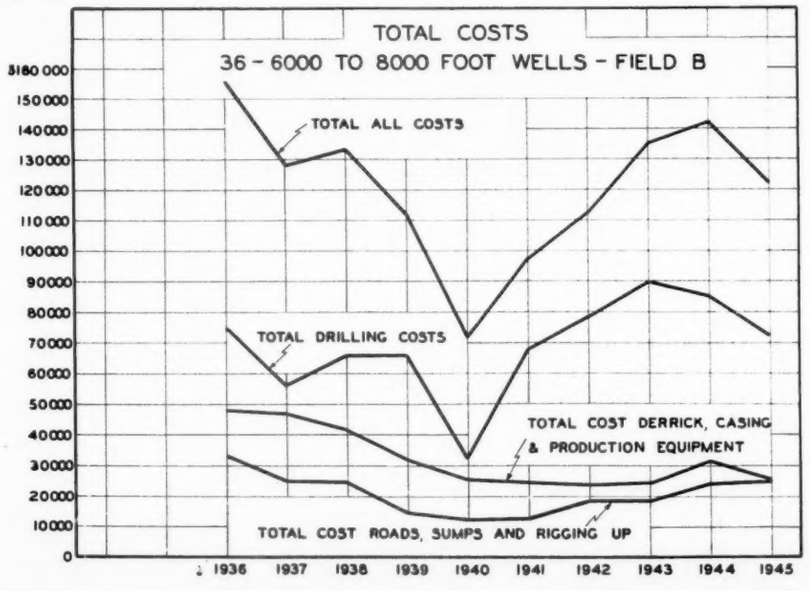
Actual *drilling* costs in 1936 averaged $75,000, decreased in 1940 to a low of $34,000, and then showed a rapid increase in 1943 to a high of $90,000. In 1945 drilling costs were approximately the same as in 1936, or $75,000, in spite of increased operating costs. This reduction is due to a decrease in the number of drilling days.

The top curve on Fig. 11 is a grand total of the three cost factors shown below and indicates a reduction from $156,000 in 1936 to $122,000 in 1945.

● **Detailed analysis of costs and days—11,000-ft. wells.** As a final group, let us consider detailed cost information on 40 deep wells varying in depth from 10,000 to 12,000 ft. These wells were all drilled in one proved field during the years 1939 to 1946.

Again, we wish to caution you, as in the case of the analysis of the last group of wells, that this is information from *one* field only; however, it is in the main typical of all fields of this depth.

FIG. 11



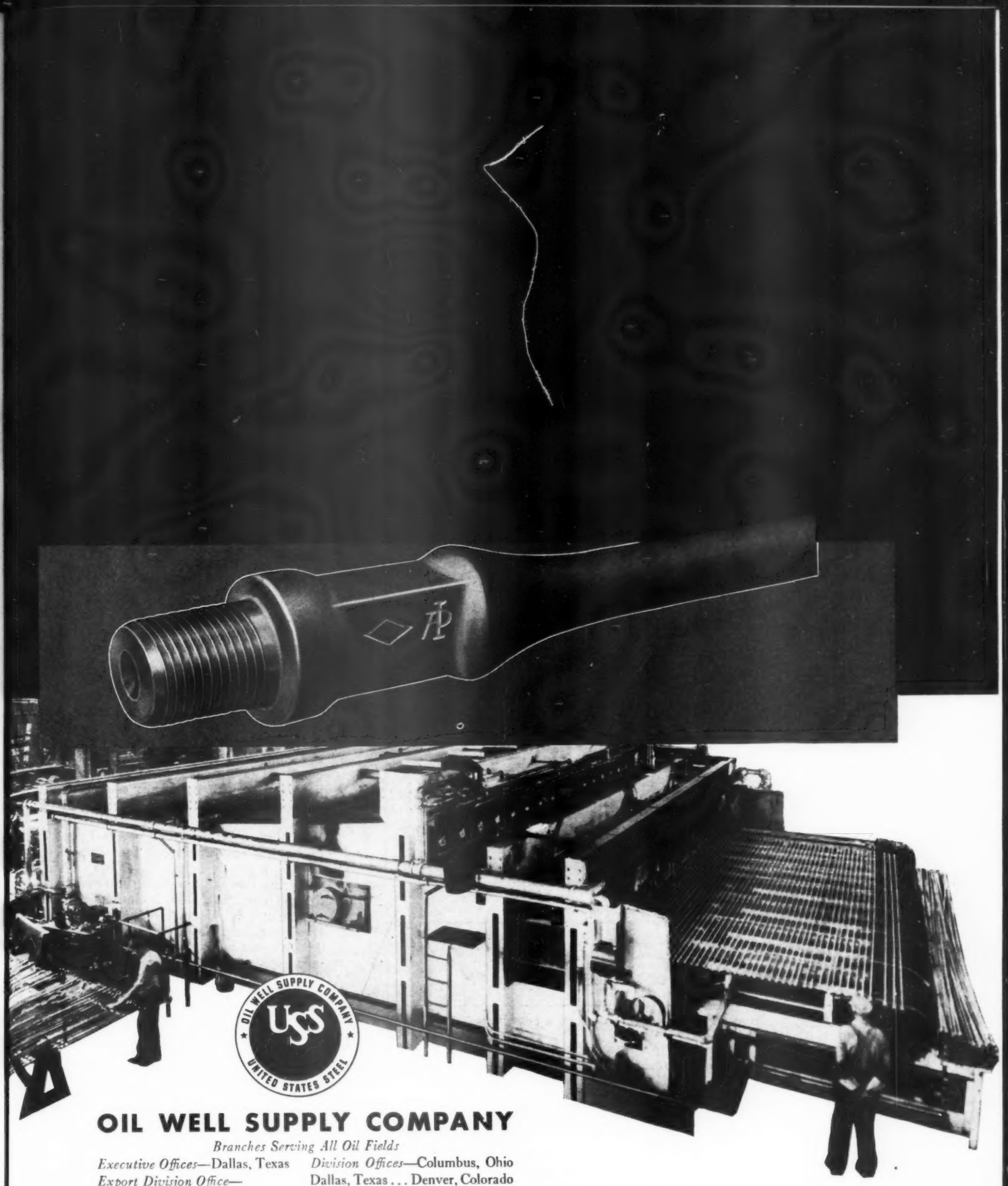


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FIG. 12

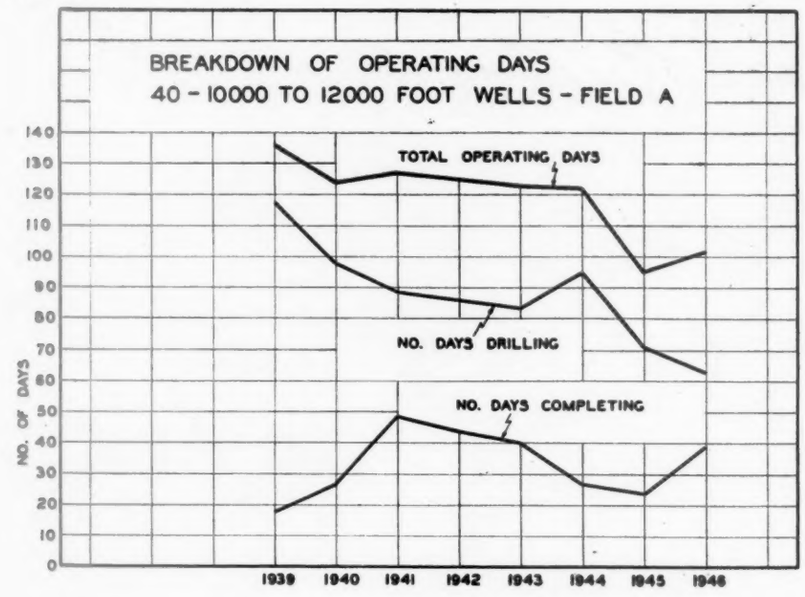


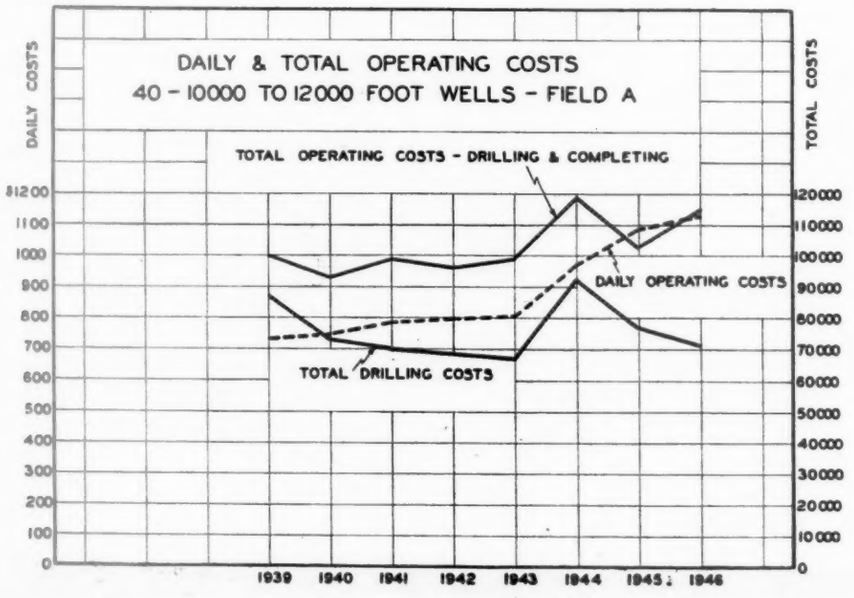
Fig. 12 shows very markedly that the number of drilling days has decreased almost 50 per cent from a total of 118 in 1939 to 62 in 1946. Contrary to the general trend in the industry, the number of days spent in completion work in this field increased sharply from 1939 to 1941 and then decreased to 1945. It should be noted that this downward trend in completion time has reversed itself during the current year and is now on the increase.

As in the case of the 6000 to 8000 ft. wells we have broken down daily operating costs in the form of a table, and it is interesting to note how this table differs from that of the shallower wells. (Fig. 13). In this case, instead of remaining constant at the same percentage, labor has increased from 23 to 28 per cent of the total. Likewise, instead of a decrease from 27 to 18 per cent in the item of repairs, supplies, and depreciation, this item has increased from $208 per day to $342 per day, or from 30 to 36 per cent of the total. Our analysis of the cause of this increase indicates a substantial expenditure for new capital equipment by this company and a consequent increase in the item of depreciation.

FIG. 13. Operating Costs Per Day for Forty 10,000 to 12,000-ft Wells, Field A

	1939		1945	
	Amt.	Per Cent	Amt.	Per Cent
Labor	$164.	23	$268.	28
Repairs, supplies and depreciation	208.	30	342.	35
Tool rental	94.	14	110.	11
Mud costs	88.	13	38.	4
Fuel and water	59.	8	47.	5
Overhead	50.	7	94.	10
Miscellaneous other	37.	5	75.	7
Total	700.	100	974.	100

FIG. 14



Tool rental per day decreased from 14 to 11 per cent, approximately in the same ratio as in Fig. 10. In the case of mud costs, we have a reduction from $88 per day, or 13 per cent, to $38 per day, or 4 per cent of the total. This, again, is in direct contrast with the increase from 1 to 6 per cent as shown in Fig. 10. It would appear that in this deep field the mud costs in 1939 of $88 per day were perhaps out of proportion and that the present costs of $.8 per day are now more nearly normal. In the case of the 7000-ft. wells the mud costs of only $8 per day in 1937 were perhaps too low for good operation, and in 1945 were more in line at $47 per day.

Fig. 14, our final chart, summarized the data on these 40 deep wells and indicates that the daily operating costs have followed the general trend of the industry and risen from $725 per day in 1939 to $1125 per day in 1946. The total *drilling* cost, in spite of this increased operating cost, has decreased from $87,000 to $71,000, which is again due to the reduction in drilling days. *Total* operating costs, including the work of well completion, have risen from $100,000 in 1939 to $116,000 in 1946, an increase of 16 per cent.

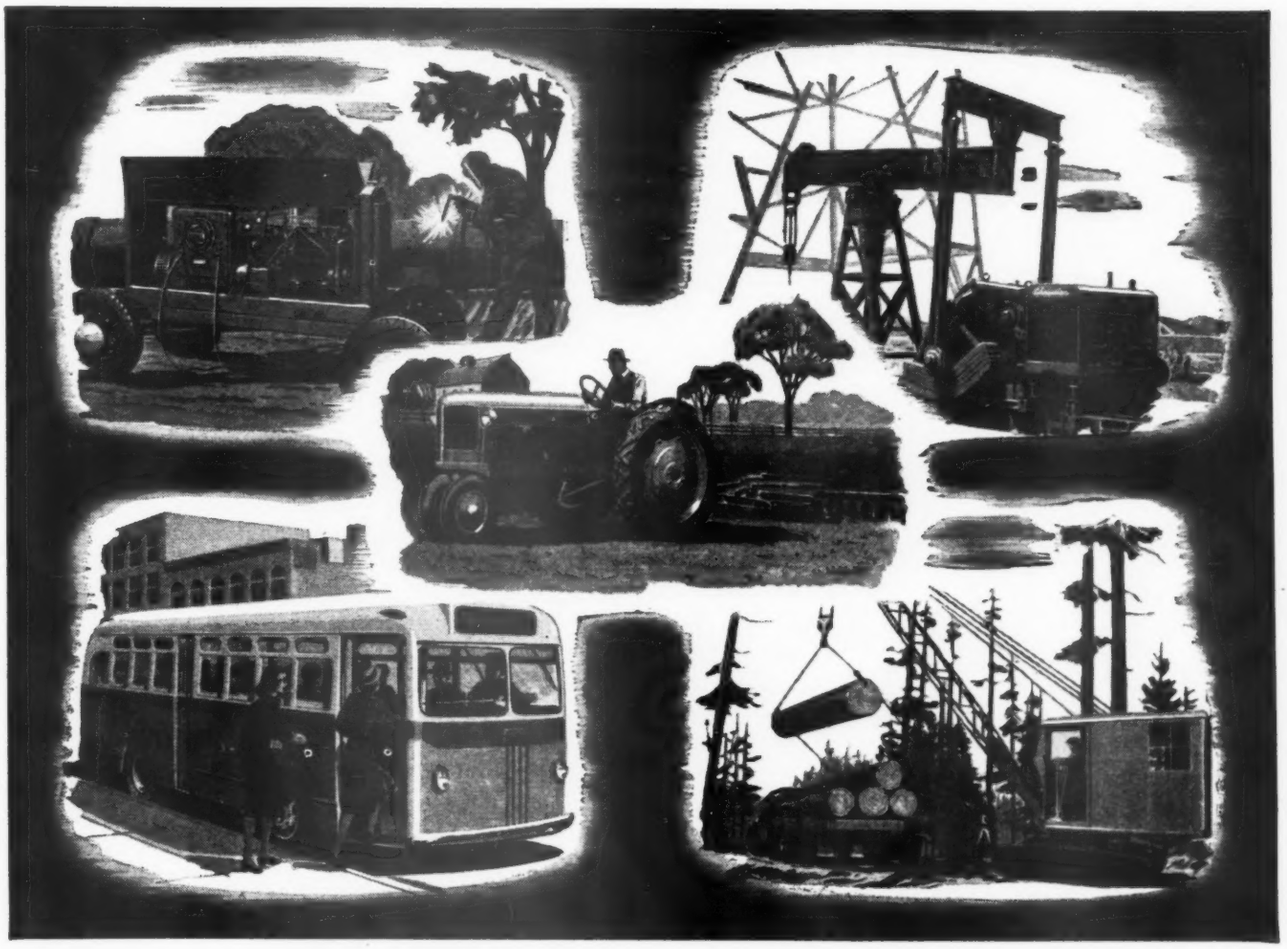
● **Conclusion.** To summarize then, we have presented in graphical form the data now available on the trends in drilling cost in California. We believe that the trends indicated in this report are representative of California operations.

We have seen that the overall daily operating cost of running a drilling rig has, regardless of depth, approximately doubled from the year 1936 to the year 1945. Further, the data have shown that the number of actual drilling days, exclusive of days spent in completion work, has decreased almost 50 per cent. With an approximate 100 per cent increase in daily costs and a 50 per cent *decrease* in drilling days, the average actual cost of making hole was about the same in 1945 as it was in 1936.

During this same period, the number of *total* operating days, including completion, has only decreased approximately 35 per cent. This reduction in total days has not been sufficient to offset the increased operating cost and, as a result, the total overall operating cost has increased some 25 per cent.

Most of the factors contributing to the increased operating costs discussed in this report are largely beyond our control. It becomes obvious that our problem is that of a further reduction in the time spent in the various drilling operations from rigging up through final completion. We suggest that a further study be made along the following lines: First, a wider interchange of information regarding improved drilling practices; second, further cooperation between manufacturers and operators in the development and application of more efficient drilling equipment; third, a study of improved means of maintenance of drilling tools and equipment; and fourth, that the results of these studies be made more available to the industry.

★ ★ ★



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Drilling Equipment Needs*

By **DOUGLAS RAGLAND**, *Engineer-in-Charge*,
Petroleum Engineering Division, Humble Oil and Refining Company

● **Introduction.** It is realized that the drilling industry is generally well informed concerning a great many drilling equipment needs. In addition to your individual experiences, several excellent trade journal articles on this subject have appeared recently. It is also realized that manufacturers have attained a high state of perfection from the standpoints of design and specification in building modern drilling machinery. They are hardly a step behind current demands of the customer. In spite of this perfection, however, the rapid increase of drilling costs as depths progress from 10 to 12 to 15 thousand feet and deeper have led many of us to wonder whether our depth records in the future will be limited by advancements in material and design or by increases in dollars per foot. It is no secret that drilling cost curves approach the vertical as the 9000-ft. mark is passed. Certainly some rather *fundamental* improvements are needed if we are to attain a more reasonable slope that will allow depths to increase at a profit. It is this need for fundamental improvements that we are concerned with here. It is sincerely hoped that some of the outstanding research talent developed during recent years will be available to solve many of the problems we suggest. Hiroshima proved that nothing is impossible, and just that type of thinking may be required.

● **Trend of drilling costs:** Fig. 1 shows the average total well cost per foot for typical wells drilled to various depths in the Texas, Louisiana, and New Mexico areas during the past two years. The upper curve is based on five wildcat and 23 proved area wells drilled in the hard formation sections of West Texas and New Mexico. The lower curve shows the average total cost of 160 proved area wells drilled in relatively soft formations of the Texas and Louisiana coasts. As a matter of interest, the maximum deviation from the curves ranges from plus or minus 20 per cent for 8000-ft. wells to plus or minus as much as 50 per cent for wells deeper than 10,000 ft. Wildcats cost some 20 per cent more than proved area wells. The deviations for those portions of the curve shown as projections, of course, cannot be predicted.

You will note that the flat, or low-cost, portion of the hard formation curve extends to about 6000 ft., whereas this portion of the soft formation curve extends to about 8000 ft. In thinking of drilling equipment needs, we are certainly little concerned with these portions of the curves. We are very muchly concerned, though, with the portions beyond 6000 and 8000 ft. where both curves turn rapidly upward and assume somewhat similar slopes to the limits of the projected data. Here is cause for real alarm. For example, the curve for hard formation drilling shows that a 7000-ft. well costs in the neighborhood of $15 per ft.; for wells deeper than 7000 ft., the cost increases so rapidly that if the depth of the well is merely doubled, the cost per foot is increased by more than 300 per cent. A worse situation holds true for wells drilled in soft formations. The curve shows that an 8000-ft. well will cost some $10 per ft. and that a well drilled to 15,000 ft., not quite twice as deep, will cost about $50 per ft., or five times as much. The economic significance to the producer of these cost-depth relationships is apparent and their trend is certainly nothing new. They are given here to emphasize that something more than minor improvements, and certainly some very fundamental improvements, are required if the reasonable cost portions of the curves are to be extended.

Where should we look for fundamental improvements? One way to approach this question is to examine the factors that make up the total cost of deep wells and consider them in accordance with their relative importance. The diagram, Fig. 2, is designed to show just such a relationship of drilling cost factors. Inasmuch as the cost of deep wells is virtually directly proportional to the time required for drilling, the chart is plotted in terms of percent of total rig time for all the various drilling operations required for an average well. This chart is plotted on the basis of the average drilling time analysis for some 70 typical wells, including 35 producers and 35 dry holes, drilled 9000 ft. and deeper in the Texas, Louisiana, and Florida areas during 1944 and 1945. The average total rig time for these 70 wells is 123 days, and they were drilled to an average total depth of 10,520 ft. As would be expected, the drilling operation alone consumes a greater percentage of the time than any of the other items, but it is discouraging to note that this drilling phase actually consumes less than half of the total rig time on the well. Items other than drilling are largely responsible for the high total-per-foot costs, and many opportunities for fundamental improvement are to be found among these auxiliary operations. Stated differently, if the cost of the auxiliary operations remained the same, the cost of the drilling operation itself could be reduced by 50 per cent and yet produce less than a 25 per cent reduction in total well cost.

● **Opportunities for fundamental improvement—rig moving.** Now, let us examine individually the various drilling operations shown on this chart and determine if equipment improvements of a fundamental nature can be suggested for each.

The operation of moving and setting up the rig consumes 6.66 per cent of the total rig time, or about 8 out of 123 days, for our typical deep well. Developments in transportation equipment and rig unitization during the past 10 years have decreased rig-moving and setting-up times to nearly irreducible minimums, assuming proper transportation equipment is available. There are no suggestions for real fundamental improvements here, but two minor cost items are worth mention: First, rig-moving and setting-up costs vary closely with the weight of the rig, and this factor should be considered in the design of improved equipment, particularly for the heavier rigs. The cost of rig equipment, including drill pipe, averages about 21 cents per lb. and the average total cost to move it and set it up is estimated at about 1 cent per lb. depending upon local conditions, which can vary widely. There is little justification for high-priced, light-weight materials, but moving costs are great enough that appreciable increases in weight must be accompanied by definite increases in efficiency. Second, an improvement not reflected by the chart is the need for low-cost, portable road materials, particularly for wildcat locations. Lumber for board roads is scarce, expensive and of generally poor quality, with little promise of change for the better in the near future. Some of the matting materials developed for portable airport service may have application here.

● **Drilling the hole.** In the majority of deeper wells, the drilling operation itself, of course, consumes a large portion of the total time on the well. For example, as shown on the chart, the drilling operation consumes 46.75 per cent of the total time on our typical well, or 57½ days out of 123. Actually less than two-thirds of this so-called drilling time is spent productively, that is, rotating on bottom and making hole, and the remainder is devoted to such nonproductive operations as round trips to change bits, reaming the hole, greasing the rig, and circulating to remove cuttings. It is natural then that many of the fundamental improvements we suggest have to do with equipment for conducting the nonproductive as well as the productive phases of the actual drilling operation. A logical division of suggestions concerning equipment for drilling is (1) needs for improvement in surface equipment, and (2) needs for improvement in subsurface equipment, and we shall discuss them in that order.

The tremendous increase in weights of surface drilling equipment that is required as horsepower rises to meet the demands of deeper drilling, coupled with the fact that the duration of repetitive operations, such as going in the hole, is greatly increased with depth, leads us to one logical suggestion—automatic machinery. The substitution of

*Presented before American Association of Oilwell Drilling Contractors, Oklahoma City, Oklahoma, October 2, 1945.

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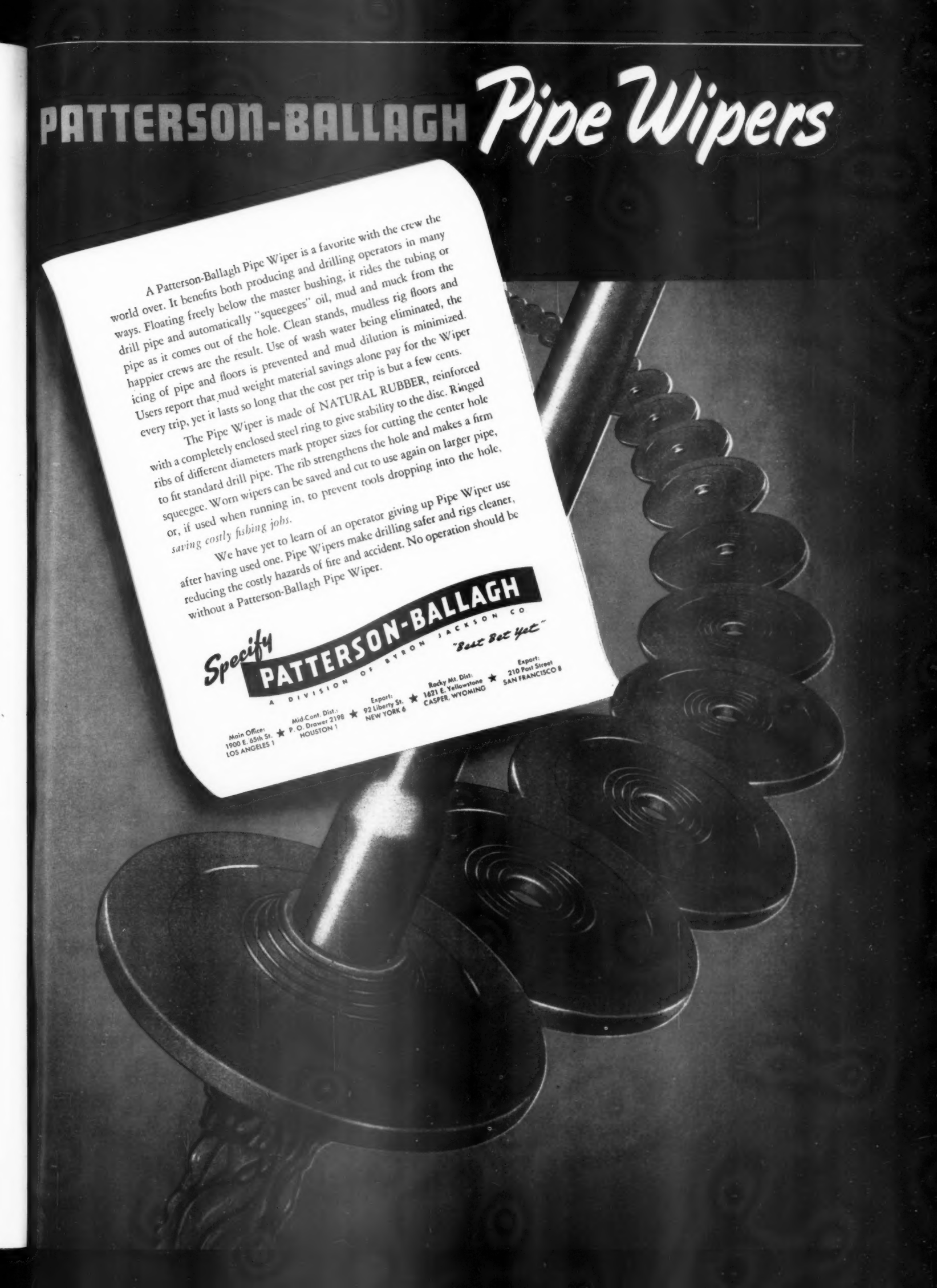

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automatic or semiautomatic power-operated machinery for many of our present more or less manual operations is probably a vital necessity if extremely deep drilling is to be carried out successfully on a production basis in the manner of our shallower drilling today. The development and utilization of such automatic machinery will not only greatly prolong the useful working life of the drilling personnel, but will allow the crews to study the performance of their equipment rather than perform with it. They will concern themselves with attaining maximum efficient results from the drilling machine as a whole in place of giving physical assistance to the various parts. The actual development of some automatic drilling machinery is now in progress. It is reasonable to expect that entirely new types of drilling machines, capable of such operations as a round trip to change bits without the help of a "working" crew, may become available for heavy duty drilling service in the near future. A dream? Yes, but so was the unitized drawworks only some 10 or 12 years ago.

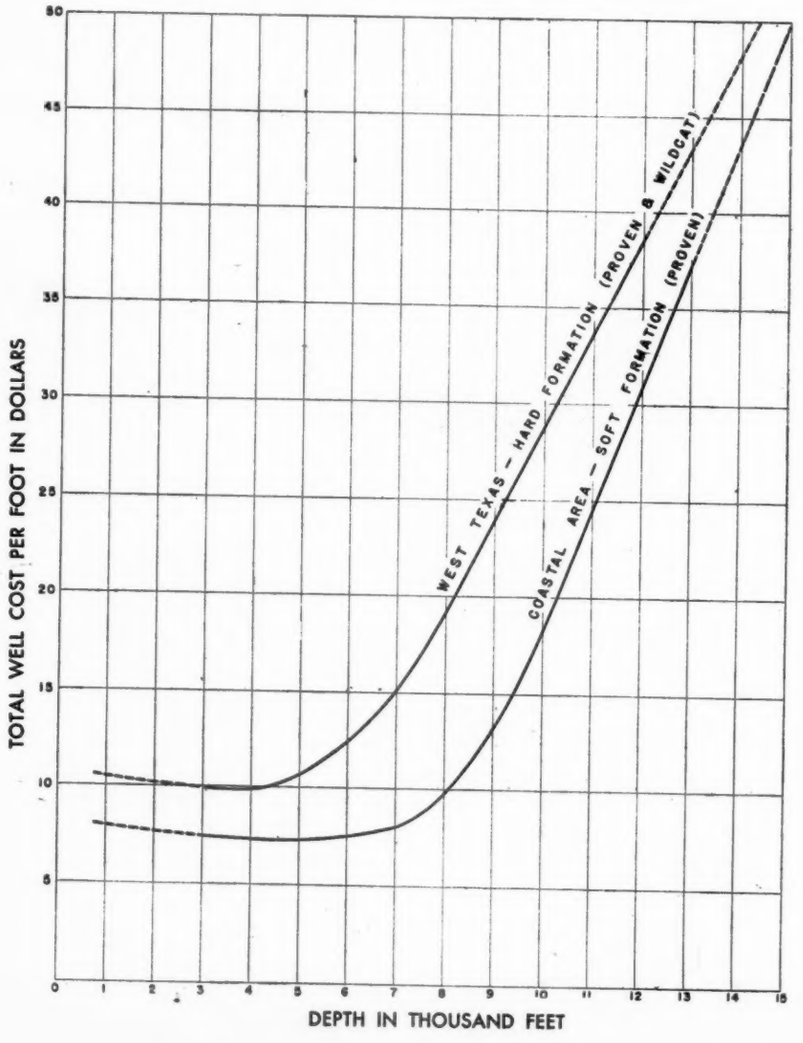
Another improvement that we consider a fundamental need in drilling is equipment for removing economically 100 per cent of the sand from drilling mud. At present, the sand content of drilling fluid cannot be reduced economically to below 3 or 5 per cent. These figures, of course, are not alarmingly high, but when it is considered that with 5 per cent sand content, a circulating system that contains 800 bbl. of mud also contains 40 bbl. of sand, there is certainly cause for concern. The removal of this 40 bbl. of damaging abrasive would virtually eliminate the costly replacement of slush pump parts, which are sand cut with discouraging speed. Furthermore, the elimination of sand in drilling fluid would make possible the application of high speed, highly efficient, and highly flexible centrifugal pumps for slush pump service. Such pumps would have immediate application on all types of rigs, and on power rigs in particular.

Speaking of pumps, numerous fundamental improvements are needed here. Steam pumps, while having excellent features for drilling service such as low first cost, light weight, and excellent performance characteristics, are costly to operate in terms of fuel. Power pumps, while economical in fuel consumption, are generally costly, heavy weight, and poor in performance characteristics for drilling service. Fundamental improvements are immediately suggested for both classes of equipment. The fuel economy of steam pumps might be considerably improved by the further development of compound steam ends; this development was begun a number of years ago by at least one manufacturer but was dropped because of mechanical difficulties in the design. The basic performance defect of the power pump, its ability to deliver only a limited pressure regardless of fluid output, that is, constant torque operation, could be eliminated by the adaptation of a variable stroke design similar to that recently developed for power plant boiler feed pump service. Such a power pump design would produce a constant horsepower performance curve even better adapted to drilling service than that of the steam slush pump. It is rumored that at least one large manufacturer is working on a power pump design along these lines.

Numerous other needs in surface drilling equipment, such as more efficient power plants, higher strength materials for wire lines, improved brakes for drawworks, more accurate depth measuring equipment, and means for eliminating or reducing that 1 hr. in 24 that is normally spent in merely greasing the rig, are well known and will not be discussed here.

Turning to subsurface drilling equipment, it appears, naturally, that improved bits and drill pipe are the only fundamental changes that can produce real increases in efficiency, particularly for hard formation drilling. We have no worthwhile suggestions to offer concerning strictly hard formation drilling, but are eagerly awaiting trial results of an interesting percussion type rock bit now ready for use in the West Texas area. We do have something of a fundamental nature to suggest as an equipment need for improving medium-hard and soft formation drilling. Here, control of hole size and not bit service, or rate of penetration, is our chief cause for concern. Using the best of the more common drilling fluids available, we are unable to control hole enlargement to a satisfactory degree. In many instances, the hole size gradually increases after the hole is made from the 8 or 9 in. drilled to as much as 20 or 30 in. This, in a large measure, is responsible for the excessive hydraulic horsepower that is required to maintain satisfactory rates of circulation in deeper holes. This effect also is the direct cause of many cases of stuck drill pipe where the heaviest circulating equipment cannot maintain adequate rates of circulation through the washed-out portions of the hole. Drilling fluids that will prevent this hole enlargement are now available, but at prices from $7 per bbl. upward, which make it prohibitive for average drilling. A fundamentally new and low-cost drill-

FIG. 1. Cost per foot vs. depth—rotary drilled wells (1944 and 1945) in typical areas, Texas, Louisiana, and New Mexico.


TOTAL WELL COST PER FOOT IN DOLLARS
DEPTH IN THOUSAND FEET
WEST TEXAS – HARD FORMATION (PROVEN & WILDCAT)
COASTAL AREA – SOFT FORMATION (PROVEN)

ing fluid that will eliminate hole enlargement would tremendously decrease the cost of drilling deep wells in soft and medium-hard formation areas. Such a mud would make possible the design of a circulating system to meet a given and predetermined set of conditions, probably with considerable reduction in pump size based on present standards. It would eliminate the need for long periods of circulation to clean the hole of cuttings and make possible the application of studies concerning the relationship of hydraulics to drilling bit efficiency.

● **Coring, evaluating formations, and miscellaneous.** Aside from completing a producer, the only other purpose in drilling a well is to discover formations that are capable of producing oil or gas in paying quantities. This finding operation is an expensive and uncertain task. The chart shows that 8.63 per cent of total well time is consumed in the coring operation alone. In addition to coring time, a considerable portion of the time shown as "Miscellaneous" is devoted to formation logging and drillstem testing, which serve further to evaluate possible producing formations. In all, an estimated 13 days out of the 123-day total rig time is used for coring and evaluating formations on a typical deep well. This figure can be even higher for some wildcats and for development wells in multiple-sand fields.

Much highly developed equipment is now available for formation evaluation, including core barrels and core analysis equipment, the various electrical logging devices, mud logging apparatus, and formation testers. The cost of using any single one of these devices would be considered little enough if a 100 per cent recovery of conclusive information could be obtained. The discouraging thing is that none of these devices tells the whole story about every type of formation and in many instances all of them used together will not effect a complete evaluation. For example, the core barrel not only misses cores occasionally but methods of core analysis are subject to error. Electrical logging devices produce a large quantity of accurate information concerning formation changes, but they do not answer the question "What will I produce if I set casing and complete a well?" Mud logging equipment, although quite promising, fails to tell the whole story concerning producing ability. Drillstem formation testers, while the most costly to use, are probably the most revealing of the devices mentioned, but here again the result is not 100 per cent conclusive. Many formations require acidization or other special treatment before they will produce and formation testers cannot perform this service. An inexpensive and thoroughly reliable equipment for formation evaluation would bring the cost of wildcats and output wells in line with that of proved area wells and would greatly reduce the cost of development wells in multiple-sand fields.

Numerous items other than evaluating formations make up the 15.92 per cent

FIG. 2. Typical drilling time analysis data on 70 wells 9000 ft. and deeper in Texas, Louisiana, and Florida in 1944 and 1945.

MOVING & RIGGING UP–6.65%
REPAIRING RIG–6.11%
CASING & CEMENTING–7.02%
COMPLETE–8.91%
MISCELLANEOUS –15.92%
INCLUDES CONDITIONING MUD SLOPE TESTS, FISHING SIDE-TRACKING, FORMATION LOGGING, DRILL-STEM TEST-ING, PLUGGING, ETC.
CORING–8.63%
DRILLING–46.75%
INCLUDES ROUND TRIPS TO CHANGE BITS, CIRCULATING TO REMOVE CUTTINGS, REAMING, AND GREASING THE RIG.

Average total depth, 10,520 ft.
Average total time, 123 days

of total rig time indicated on the chart for miscellaneous operations. These include mixing mud, running slope tests, fishing and sidetracking, waiting on orders or material, and plugging to abandon. While certainly subject to minor improvements, these items suggest nothing of a fundamental nature.

● **Well completion, casing and cementing.** The final product of the drilling rig as far as the customer is concerned is not merely a deep hole in the ground, but a completed well ready to produce. In many fields where drilling costs are relatively low, completion difficulties make the total well costs quite high. For the typical well shown on the chart, 11 days out of 123, or 8.91 per cent, are consumed in completion operations.

Some fundamental improvements in cementing materials would produce a substantial decrease in well completion time. Casing, liner, and formation cementing have always been difficult tasks, and these difficulties have led the industry to seek relief by demanding cements with higher and higher tensile strengths. It is now questionable whether these demands have been justified. For example, the chief deficiency may not be low strength cement, but rather the inability of the cement to set up and form an impermeable seal when mixed with drilling fluid. In other words, contamination and not low strength has been one cause of trouble. Furthermore, high strength is a distinct disadvantage when completions are attempted by perforating cemented casing. It follows then that a fundamental equipment need of the industry is a cement of reasonable tensile strength, low resistance to perforation, and the ability to set up and form an impermeable seal between the casing and the formation when thoroughly contaminated with drilling fluid. This cement should also be made acid proof in order that simpler and more successful completions can be effected in lime formations. Many of our most expensive completion jobs are carried out in lime-producing fields where the acid that is necessary to effect oil production destroys the cement job that is placed to protect that oil production against gas and water channeling.

Many other improvements, such as higher tensile strength and heat resistant packer sealing elements, longer life swab sealing materials, and casing perforating devices with increased ranges of penetration, would contribute to reductions in completion cost, but these are considered minor in comparison with the need for an improved oilwell cement.

Casing and cementing time takes some 8½ days, or 7.02 per cent, of the 123-day total rig time for a typical deep well. This in itself is not a particularly large item and offers but little chance for improvement; however, when it is realized that about two-thirds of this casing and cementing time is not actually used for running casing and pumping cement, but constitutes time spent while waiting for cement to harden, we have something worth thinking about. The specifications for an improved oilwell cement should certainly include a lower-than-present setting time, retaining, of course, the required period of pumpability. This improvement alone would effect up to a 5 per cent saving in total well time for average deep drilling conditions.

● **Rig maintenance.** With present rigs the 5 per cent saving in total well time that could be realized by the elimination of cement waiting time would not be a real saving. This period is actually spent in repairing and reconditioning the rig. In addition to this 5 per cent, another 6 per cent of the total well time, as shown on the chart, is devoted to rig maintenance. Eleven per cent shut-down time definitely calls for fundamental improvement. It may not be reasonable to expect that a drilling rig can be made to equal the performance of the ordinary household refrigerator, which often runs 8 to 10 years without attention, but there is room for fundamental improvement in a record of 1 day shut down in 9. Design for far greater overload conditions is certainly a basic suggestion here.

● **Conclusions.** In conclusion, the critical examination of the operation of present drilling equipment suggests many possibilities for fundamental improvements that should result in greatly decreased deep drilling costs. Indeed, it is plain that such fundamental improvements must be made if costs *are* to be reduced greatly. Only research can provide these advancements. It is believed that the industry today is ready to put research men on the job in the increased numbers that will be required.

● **Acknowledgment.** Appreciation is extended to the many members of the Production Department of the Humble Oil and Refining Company who assisted in obtaining data, and to the management of the Humble Oil and Refining Company for their permission to prepare and present this paper. ★★★

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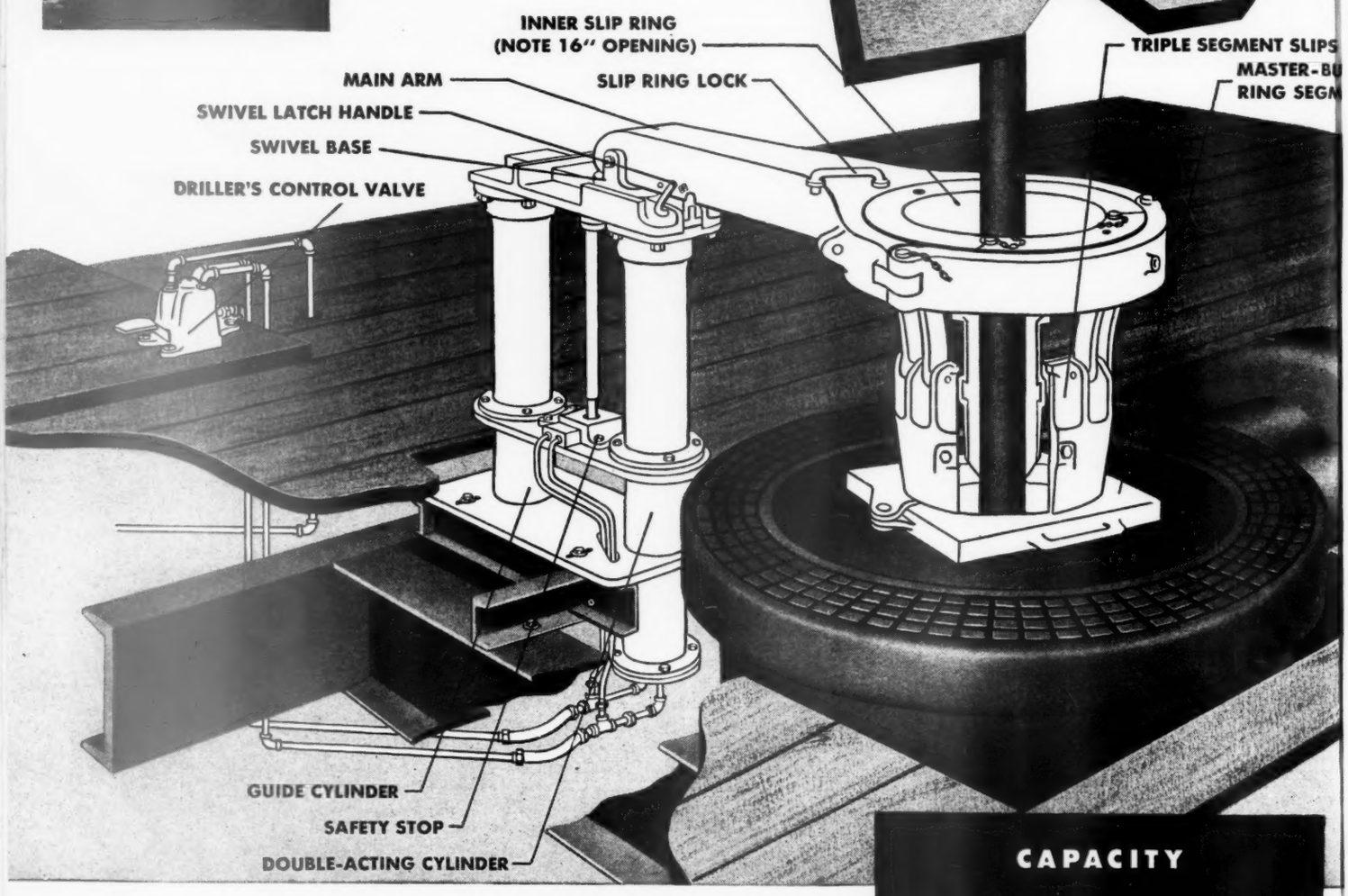

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(Right) These are the working positions for fast, smooth round trips. Slips are set or raised by a simple movement of the driller's foot lever. Slips are pressure-locked in both raised and set positions. In case of a power failure when slips are raised, the safety stop prevents slips from dropping.

(Above) Snaking slips from out-of-service position into working position with the catline is simple and fast. Note how main arm swings open on hinge pin, and how slip ring segment is locked to hinged arm for this operation. After dropping the mechanism into working position, the main arm is swung closed and the chained retaining pins are reinserted.

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Results and Use of Oil Base Fluids in Drilling and Completing Wells*

By **GLENN V. KERSTEN,** *Production Engineer,* Western Gulf Oil Company

● **Abstract.** Evidence is shown indicating an improvement in initial well productivity with the use of oil base fluids. There is inadequate evidence that the improvement is of lasting benefit. More records are necessary for additional evidence.

Swabbing, scratching, or washing are seldom necessary for well completion when using oil base.

The effect of oil base on drilling operations tends in general to increase rig time and expenses. Precautions are necessary to prevent fires, water contamination, and unnecessary fluid losses. Completion problems are mutiplied if the program calls for more than a drilled hole with a liner. Cement work on blank sections and squeeze work on gun perforations is not as easy as with water base.

The expenses of drilling and completion with oil base are increased over that of water base. Improvements in technique and handling should reduce future costs.

● **Reasons for use of oil base.** The majority of oil personnel are intensely interested in obtaining the best possible type of well completion under operational conditions. Every effort is made to obtain maximum oil entry and maximum continued production of oil. Drilling fluids are conditioned to the lowest possible water losses through the oil zones. Oil base fluids are being used where conditions of sand fluid content and low permeabilities indicate the necessity of the smallest possible water loss fluid.

Shortly over a year ago the industry was shown the results of numerous permeability tests on core samples of differing types of sands. (1) It was demonstrated that sands containing hydratable material or exceedingly tight, are seriously affected by contact with water, lowering the permeabilities, in many cases, to an alarming extent. Fresh water affected the cores more than salt water. It was indicated that in many instances no water at all would be beneficial and that wells completed or repaired with a fluid having no water loss would perform more satisfactorily.

The only drilling fluid at hand that will fulfill the above conditions is an oil base fluid. Almost everyone is convinced from basic premise that this is the best type of fluid with which to penetrate or work on an oil zone. Yet, to date, there is a lack of factual evidence that substantiates an initial and continuing improvement through a variety of conditions.

● **Results of use of oil base fluids.** Earlier investigations have shown[2 3] that there is an initial indicated improvement in well completion from the use of oil or oil base fluids. Figs. 1 to 7 were developed to show that this indicated improvement is not confined to one field or one set of conditions. The figures shown are for five different fields; four from the southern portion of the San Joaquin Valley, and one from the Los Angeles Basin Harbor Area. Type of sands vary from low permeable sands containing hydratable material through high permeable clean sands and high permeable silty sands. In every field for which data were available, it is evident that an indicated initial improvement is made in the ability of the oil zones to yield fluid per pound pressure draw-down.

The plot of the ability of the sand to yield fluid per pound pressure drawdown against the number of millidarcy feet of sand open was chosen as the best yardstick with which to measure well capacity for any one set of conditions or field. In general, for the same millidarcy feet of sand, there is an indicated improved difference between oil base initials and water base initials, although there are a few cases where the oil completions are not so good, and where the water base completion is exceptionally good. It is also indicated that wall-scraping with oil base after penetration with water base is better than water base.

It is important that the possible improvement gained by oil base completion be maintained, for there are numerous cases of well productivity increase several months after water base completion. It is possible that the initial increase

*Presented before American Petroleum Institute, Pacific Coast District Division of Production, Los Angeles, April 12, 1946.

FIG. 1. Initial comparison. Oil base vs. water base. Field "A", Central San Joaquin Valley.

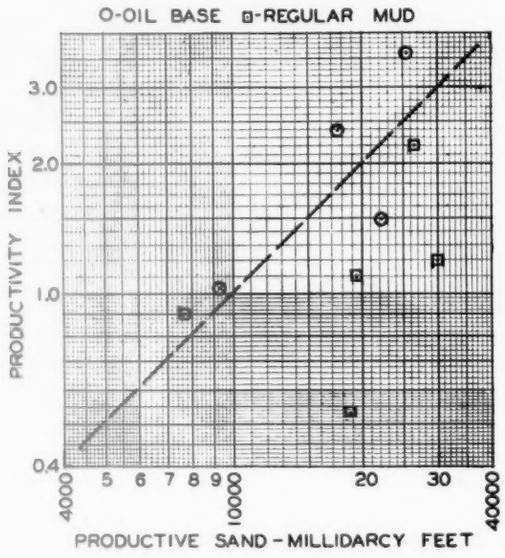
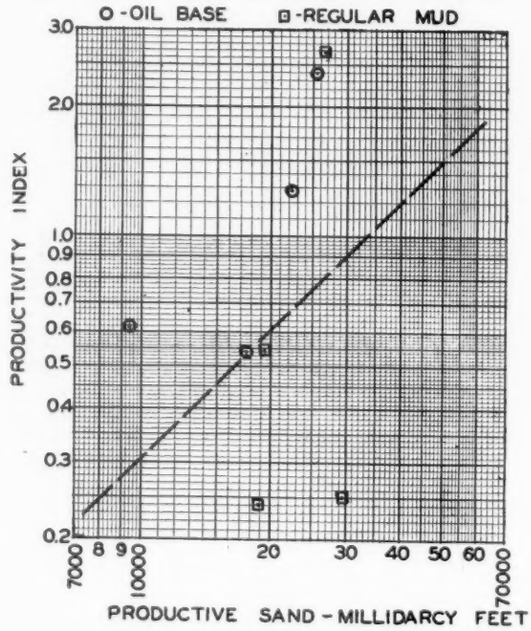


FIG. 2. Comparison after producing 200,000 bbl. oil Oil base vs. water base. (Same field as Fig. 1.)



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from oil base could be caught up with and even surpassed by many water base completions. In the event this happened, the initial bother and expense from the use of oil base will have been in vain.

Figs. 2 and 4 were assembled to give an idea as to what happens after producing several thousands of barrels of oil. Only two fields were found with enough experience data to plot, although there are numerous cases of oil and oil base completions of long years standing. Field "A" first had oil base completions during 1939 and 1940. Field "B" had oil base completions during 1942. Good records were kept as to productivity and volume. Both fields seem to indicate that the initial increase has been sustained through the production of 200,000 bbl. of oil from wells in Field "A" and 150,000 bbl. of oil from wells in Field "B". Unfortunately some of the wells completed and wall-scraped with oil base in Field "B" had to be shut in due to high ratio.

If this indicated sustained spread could be substantiated by more and better records, a true evaluation of the results of oil base on well capacity and recovery could be made. It is suggested that wherever possible, permeability, net oil sand, and productivity index data be gathered so that an evaluation of the lasting effects of oil base completions can be made before depletion occurs. It is not enough to show the management that the well flowed more initial oil and seems to perform better.

Other benefits derived from the use of oil base is in completion work and in the possibility of obtaining better interstitial water content. Completions are, in general, made easy for flowing wells since it is usually only necessary to displace the oil base with oil and the well will either flow immediately or after several hours. Swabbing time is largely eliminated. Its use opposite low pressure sands eliminates the expense and work involved in washing and scratching. Fluid is changed to oil and the well is pumped in.

● **Use of oil base fluids.** Oil or oil base fluids have been in use for a great many years and in numerous fields. At present, oil base is, or has been, used in nearly all fields in the state. Depth of hole or temperature conditions offer no problem at present, for suspending agents for weight and viscosity control have been developed to a high degree of efficiency. Water has a detrimental effect on all oil base fluids, but can be controlled by the addition of slacked lime. Most operators experience no trouble with up to 10 per cent water content.

It is often necessary to change casing programs when using oil base, for it is dangerous to have such fluids opposite a long open hole. The usual procedure is to obtain a primary water shut-off above the oil zone, then change to oil base to drill into the horizon. Open hole up to 2000 ft. has been maintained satisfactorily. A sacrifice in hole size is necessary unless the expense and time for under-reaming or wall-scraping is deemed advisable.

● **Effect of oil base on drilling problems.** The use of oil base multiplies the problems of drilling operations. Drilling crews have to have extra compensation, usually 75 cents per day per man. Fire hazard has to be guarded against with rigid rules. A large amount of time and material is spent on pump repairs, although the newer type rubbers for pistons and valves will last longer than the older types up to 1500-lb. circulating pressure, above which the usual amount of trouble is to be expected. It is often necessary to repair one pump while the other is in use, one pump being down continually.

As the cost of oil base fluids is excessively high, it is necessary to guard againts losses. A wiper must be used on the drill pipe or tubing. The standback should have two drains, one to the ditch for oil and one outside for washing. Water-cooled drawworks and steam engines should have special guards to prevent water getting into the cellar. Mud pits have to be protected from water drainage. Storage tanks are needed, especially where the operation is isolated from a central and mixing pit.

Use of oil base results in smaller hole sizes than where the zone is normally penetrated before any casing is run. Footage per bit is lowered due to the smaller sized drilling or coring heads. Experience has shown that for the same size bit, shales will drill about the same as water base muds, but sands will drill considerably harder and will take more bits to make the same footage.

All the above has a decided effect on rig time, since all tend to increase the amount of time spent on the same length of hole. Drill time chart, Fig. 8, shows the effects visibly although considerable time was spent on oil base holes "A" and "B" by under-reaming and special testing for required structural data, which should be deducted in making a comparison to wells "C" and "D".

The operator first using oil base is apt to experience considerable "growing pains" when handling oil base and should, if possible, use the experience of his neighbor to avoid unnecessary costs.

Oil base costs vary from $5.00 to

FIG. 3. Initial comparison. Oil base vs. water base. Field "B", West Central San Joaquin Valley.

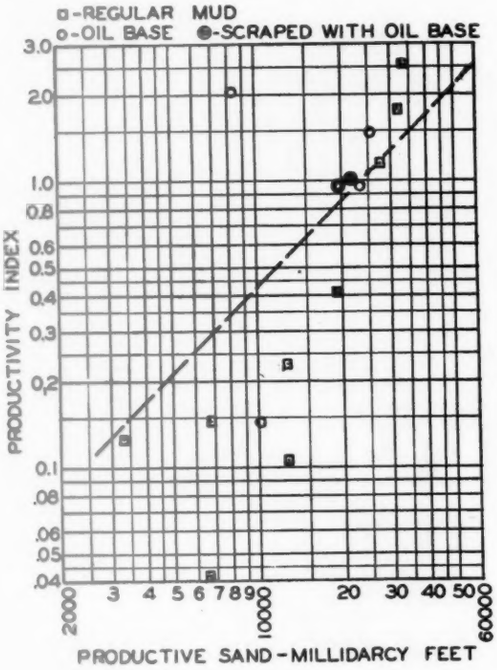


FIG. 4. Comparison after producing 150,000 bbl. oil. Oil base vs. water base. (Same field as Fig. 3.)

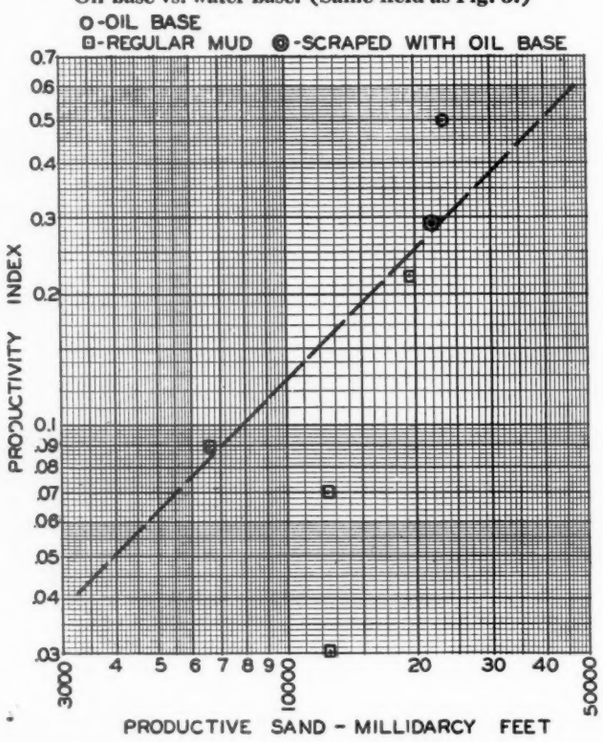


FIG. 5. Initial comparison. Oil base vs. water base. Field "C", South Central San Joaquin Valley.

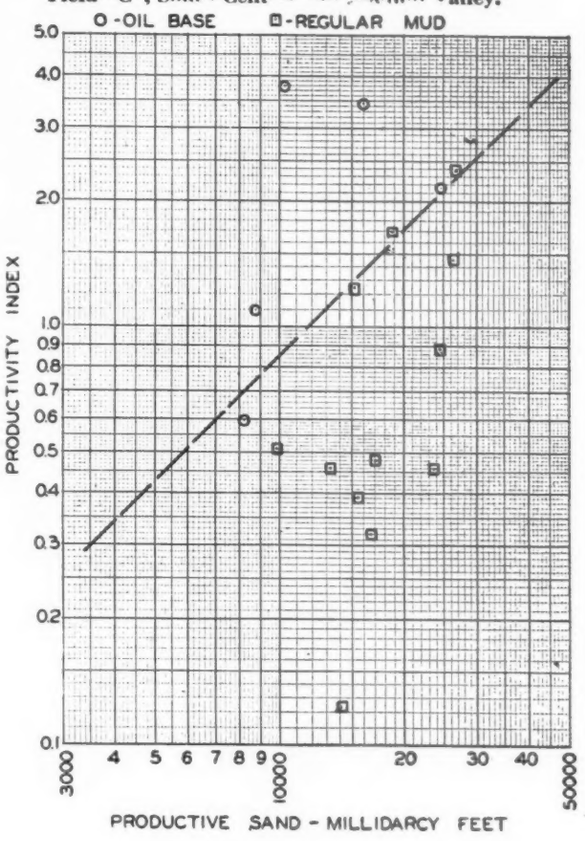


FIG. 7. Initial comparison. Oil base vs. water base. Field "E", Harbor area, Los Angeles Basin.

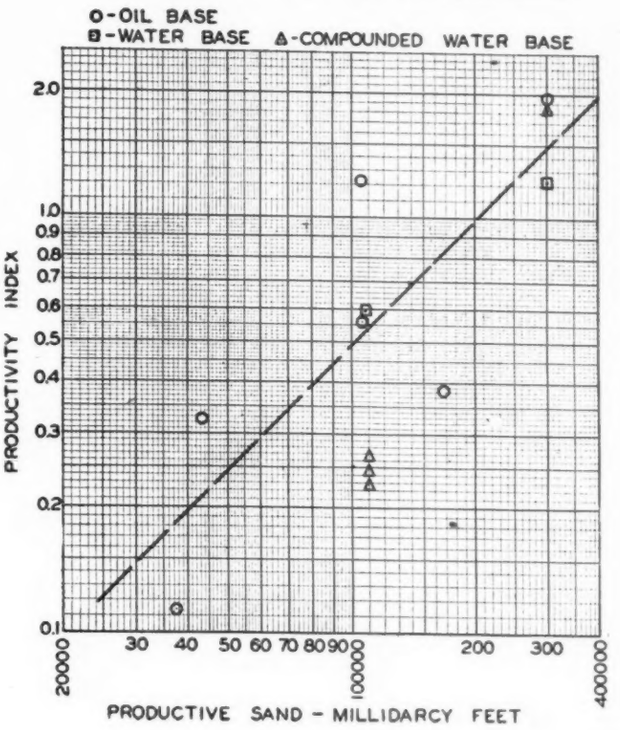
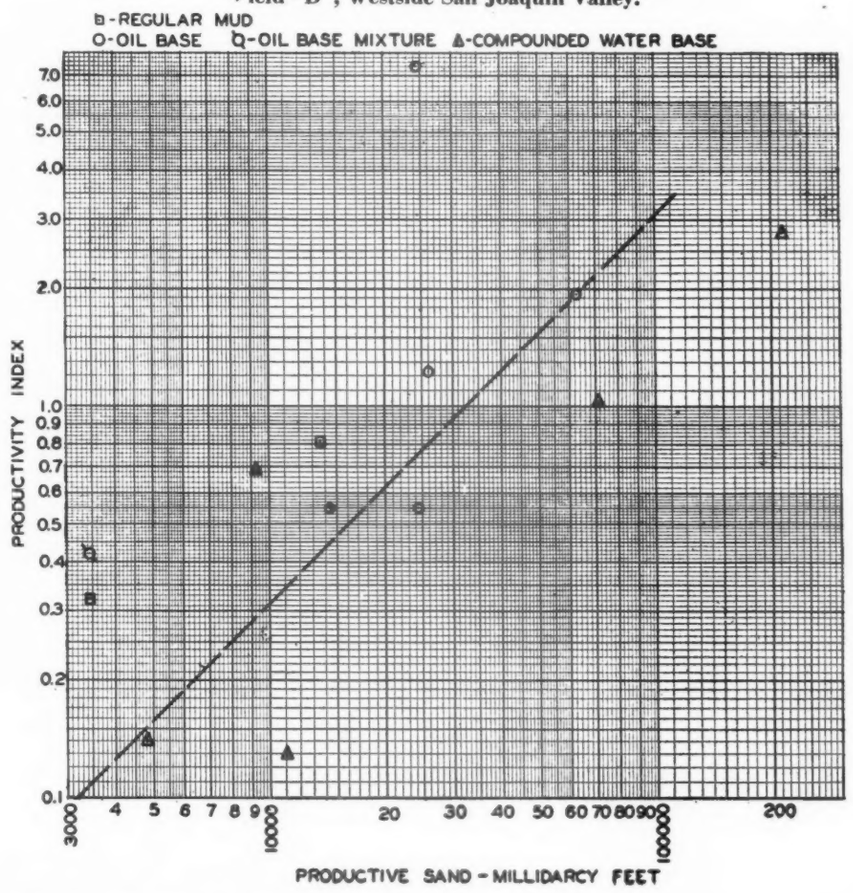


FIG. 6. Initial comparison. Oil base vs. water base. Field "D", Westside San Joaquin Valley.

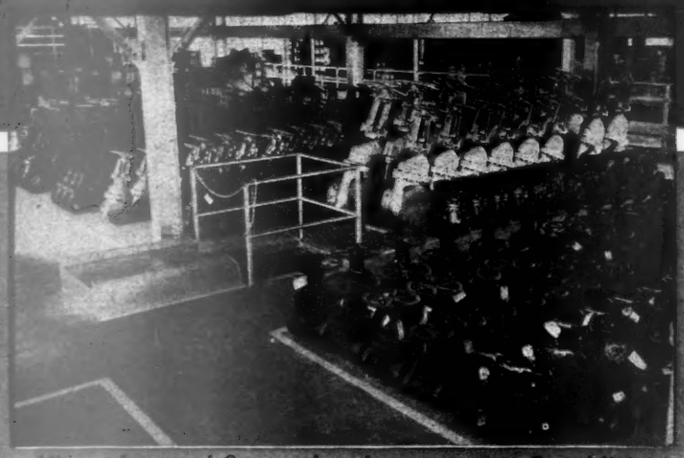


$10.00 per bbl. for light weight muds (68-75 lb.), and from $10.00 to $15.00 per bbl. for heavy weight muds (75-85 lb.). Losses per hole in use vary from 50 to 150 bbl. with an average of about 100 bbl. Precautions outlined above will cut losses still further. The fluid may be used a number of times in different holes. Assuming that there is a loss of 100 bbl. per hole, and a depreciation of ⅛th per hole of 400-bbl. fluid content, six holes may be completed with 1000 bbl. of stock oil base. This spreads the cost considerably. Where operations permit, a central mud storage and mixing plant is very desirable.

● **The effect of oil base on completion problems.** Where the completion program can be made simple, as in drilling or coring the hole and setting a perforated liner, running tubing, and bringing the well in, the completion problem is not seriously affected except as to rig time and extra mud expense. If the program for completion involves intermediate waters and the necessity of cementing blank liners, or blank sections, an amount of extra time will be found necessary to complete.

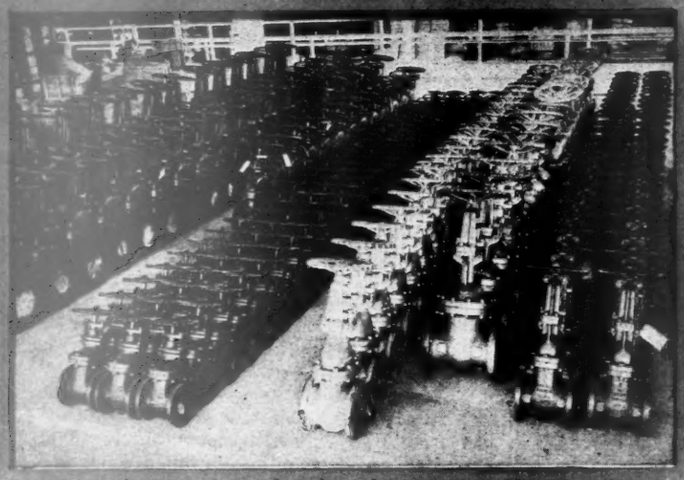
Electric logging equipment for oil base has been improved and it is now possible to make fair correlations on major breaks in the oil zone. It is not satisfactory for third curve work or for minor markers or for sand counts. Correlation Section, Fig. 9, shows three oil base and three water base electric logs for a field in which normal water base electric log correlation is sometimes difficult. The

A SUPPLY SERVICE as



View of second floor valve department at Republic's new Houston store

A section through the plug valve department



Another section of valve department showing assortment of various sizes

Close-up view showing method for handling fittings and shelf hardware

Partial view of flange stocks

Welding fittings department

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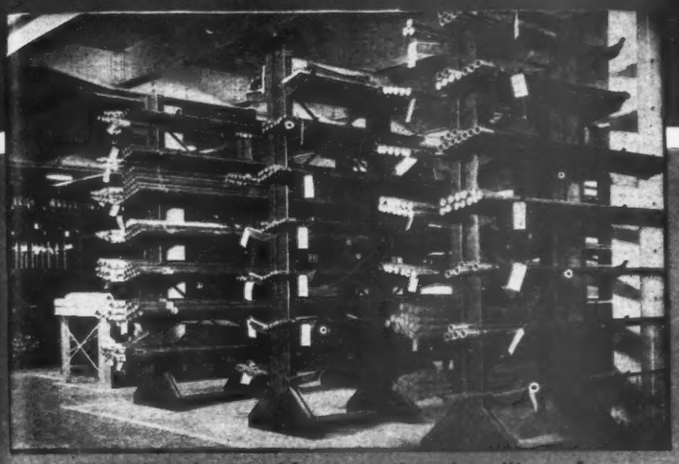

Steel racks provide convenient handling of sub-surface pumping equipment

Looking north along east aisle of main floor. Plant has more than 37,000 square feet of space

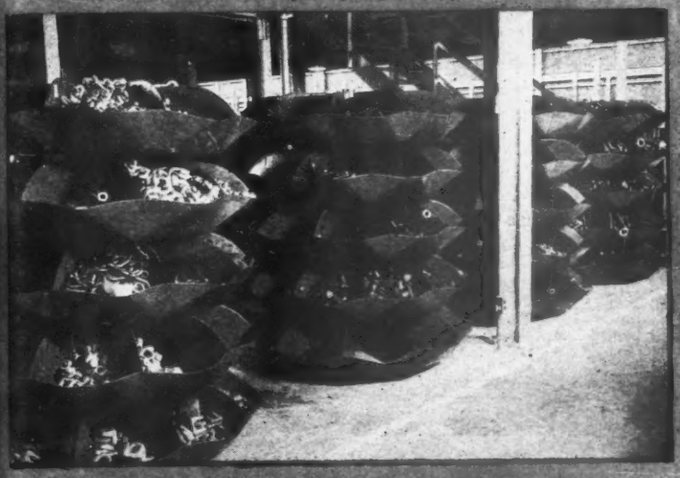

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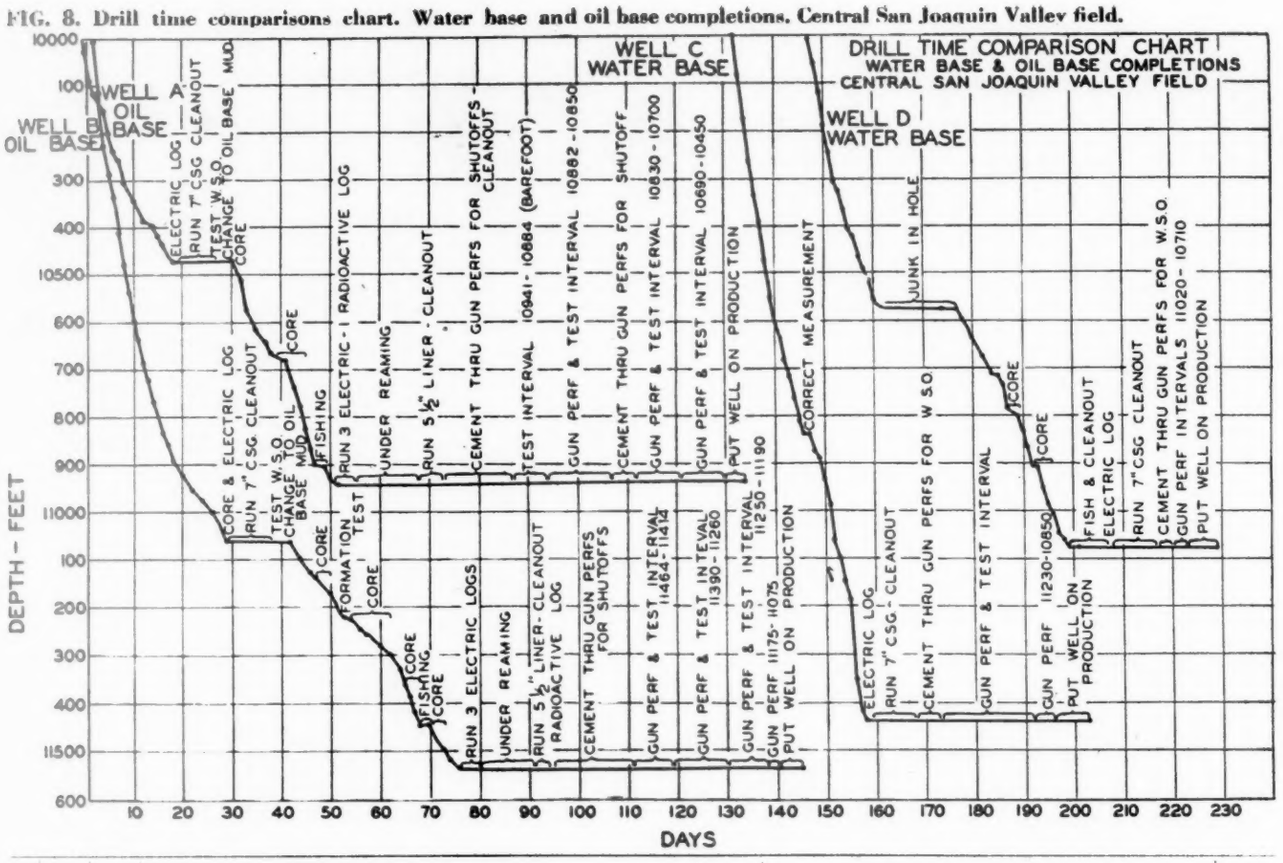
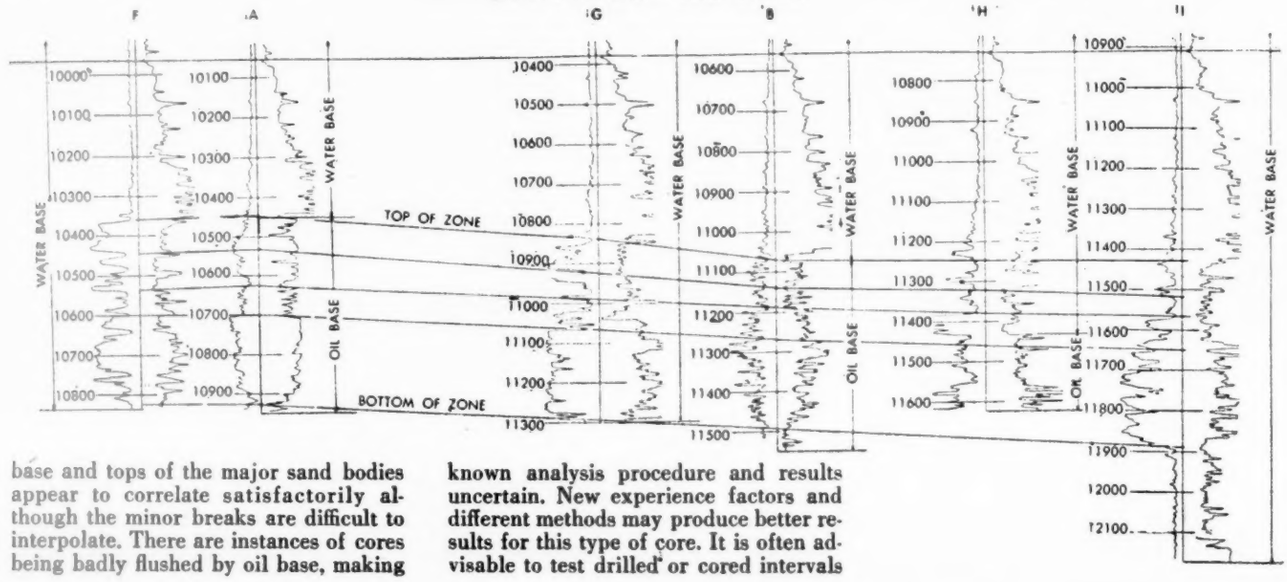
FIG. 8. Drill time comparisons chart. Water base and oil base completions. Central San Joaquin Valley field.



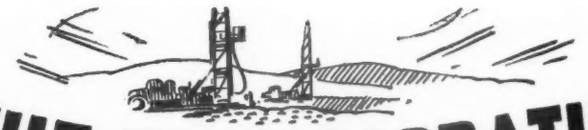
Well	Type mud	Total depth	Drilling data, top of zone to total depth											Days running 7-in. casing and W.S.O.	Completion data, total depth of completion								Days top of zone to completion
			Days top of zone to T.D.	Feet top of zone to T.D.	Footage drilled	Days drilling	No. of bits	Feet per bit	Footage cored	Days coring	No. of days cemt. hole	Feet of cemt. in hole	Days fishing		Days logging	Days underreaming	Days running liner & cemt.	Days gun perforating	Feet perforated	Days testing intervals	Lost time fishing	Lost time and misc.	Days T.D. to completion	
A	Oil Base	10,941	33	481	404	13	19	21	78	5	7	11	2	13	2	12	19	5	382	36	0	7	83	118*
B	Oil Base	11,537	45	466	229	14	20	11	237	12	23	10	4	9	4	11	18	7	340	22	1	7	70	115*
C	Water base	11,437	11	587	587	10	16	37	0	0	0	..	1	14	1	..	..	8	420	15	1	6	44	55*
D	Water base	11,073	16	361	66	4	5	13	294	12	17	17	0	14	1	..	..	3	270	0	5	7	30	46

*For comparison deduct time for underreaming and testing.

FIG. 9. Correlation section. Comparing oil base with water base electric logs. South Central San Joaquin Valley field.
Scale: 1 vertical = 2 horizontal.



base and tops of the major sand bodies appear to correlate satisfactorily although the minor breaks are difficult to interpolate. There are instances of cores being badly flushed by oil base, making known analysis procedure and results uncertain. New experience factors and different methods may produce better results for this type of core. It is often advisable to test drilled or cored intervals



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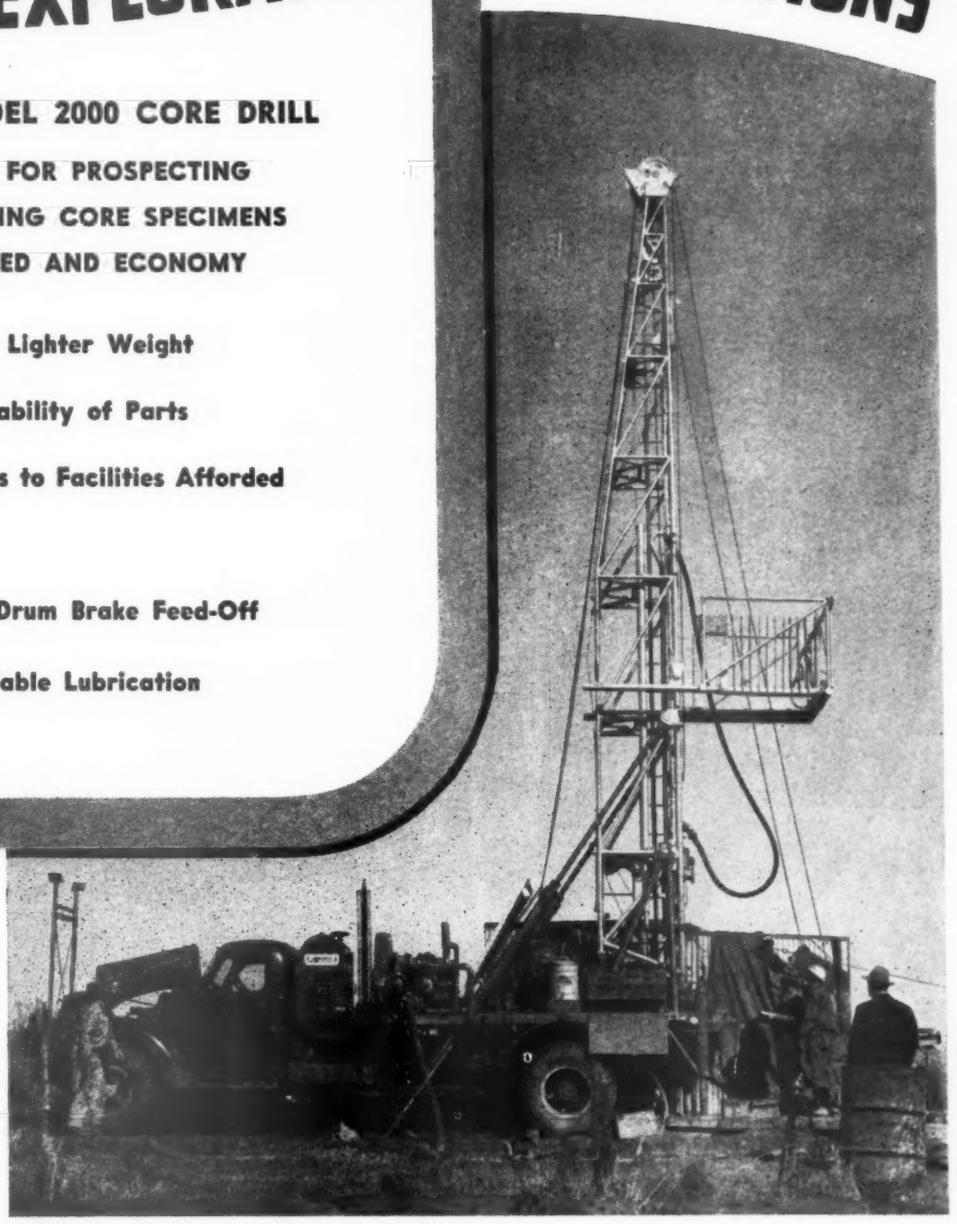

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to determine the proper fluid content.

Open hole packer test work seems to be more positive with oil base than with water base. One company that makes open hole interval tests as a part of completion practice, has not had a stuck packer that could not be jarred loose easily.

Obtaining satisfactory cement jobs in oil base is difficult without certain precautions. A quicker job is effected by running a hole caliper and figuring the amount needed therefrom and by preceding the cement with distillate. Since the oil base was installed to prevent water contamination to the oil zone, it is not good practice to precede the cement with water or water base mud, although a more positive cement job would probably result.

Gun perforating does not present a problem. It can be done with as much ease as in water base fluids. There is no known effect on scraping and wash work.

Experience has shown that considerable packer trouble is encountered in making casing tests of hole intervals. The light refined oils used in compounding the oil base fluid attacks the packer rubbers and causes failure, or, the weighting material masks the slips to such an extent that a good hold is not obtained. Newer packer ring designs and use of drillable bridge plugs have improved packer seals.

● **Effect of use of oil base on drilling and completion costs.** As shown above, the use of oil base can materially increase the cost of completing a well. Added shallow hole cost is very small since it is difficult to find any difference in drilling and rig time. Cost per hole for shallow drilling will run from $2000 to $5000 per well for materials and handling. A deep hole of 10,000 ft. or better with 500 ft. of oil horizon will show considerable added rig time using oil base, as outlined previously, to make the same hole. Costs will likewise go up. As an example, assume heavy oil base required to hold down a well and 15 extra days rig time to drill the 500 ft. of hole, run casing, gun perforate and do the necessary cement work for secondary shut-offs. The heavy oil base will average $13.50 per bbl. to mix and maintain in usable shape. Since it was estimated previously that 1000 bbl. would drill six holes, the cost per well would be $2250. Fifteen days extra rig time at $650 per day is $9750. Extra tools and fuel is estimated to be $3000. Total $15,000 or $30 per foot added cost due to use of oil base. Experience and improved technique in handling and use should reduce future costs.

● **Conclusions:** The use of oil base appears to improve the initial ability of a well to produce oil. Inadequate history indicates that the improved position of well productivity index is maintained.

Well completion practices are improved. Swabbing, washing, and scratching is seldom necessary.

The effect of use of oil base on drilling operations tends, in general, to increase rig time. Precautions are necessary to prevent fires, water contamination, and unnecessary fluid losses.

The effect of oil base on completion problems is noticeable where the program calls for more than a drilled hole with a liner. Cement work on blank sections and squeeze work on gun perforations is not so easy as with water base.

The expenses of completion are usually increased from $3.00 per ft. on shallow holes to possibly $30.00 per ft. on deep holes where necessary secondary shut-offs are made. Improvements in technique and handling should reduce costs in the future.

The operator first using oil base is apt to experience excessive costs until his men are properly educated as to technique of handling and saving the oil base.

● **Acknowledgements.** Thanks are gratefully expressed for the help and criticism extended by the various companies and company personnel which contributed data. The author also thanks company personnel for aid in preparation and the Western Gulf Oil Company for permission to prepare and publish.

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Improved Drilling Muds Containing Carboxymethylcellulose*

By H. H. KAVELER†

● **Introduction.** Modern practice in the rotary method of drilling well bores is generally considered to date from the use of rotary tools in the Spindletop field in Texas in the year 1901. Rotary drilling is a method primarily dependent upon a practical means of continuously removing cuttings from the well bore as drilling proceeds. This is accomplished by circulating a fluid through the drill-stem and bore-hole annulus. Any fluid might be used for the purpose that under flow conditions existing in the circulating system has the capacity for suspending and carrying earth cuttings to the surface. Water was first used, and, is the fluid most generally employed. Oil has been employed on special occasions in recent years, and, in some instances, gas has served the purpose.

It would require no involved study to determine how it was that water was used as the circulating fluid became known to the industry as "drilling mud". Any liquid, and particularly water, on being circulated in contact with the bore-hole cuttings would soon become an admixture with finely divided insoluble minerals in suspension, and, with some quantity of soluble minerals in solution. Such a mixture of earth and water would to the ordinary being have the appearance of "mud", even though the name, as drilling mud is known today, is perhaps not the best choice of nomenclature. It is interesting to observe, however, that drillings muds were first unavoidable dispersions of both insoluble and soluble earth minerals in water. Such a mud resembled a modern drilling mud only in the general respect of being a dispersion of both soluble and insoluble materials in the circulating fluid. In present times, one of the important problems in the maintenance of drilling muds is to maintain control of the properties of the mud under the destructive effect of the unavoidable additions of the mud encountered in the course of drilling.

No historical account is generally available that traces the development of drilling mud, and particularly traces the development of the understanding that led to modern conceptions of its function and purpose in drilling. Nevertheless, it would appear that the industry soon recognized that drilling mud served many functions other than that of simply removing cuttings as drilling proceeded. The function of mud as a means of back-pressure control must have been very early recognized.

†Assistant to vice-president, Production Department, Phillips Petroleum Company, Bartlesville, Oklahoma.

*Presented before Mid-Continent District API Division of Production, Oklahoma City, Oklahoma, June 6-7, 1946.

The necessity for back-pressure control led to the addition of finely divided heavy-mineral substances for the purpose of increasing the specific gravity of the mud. The most practical choice of such a weighting material led to the universal use of the mineral barite. Addition of weighting material was, perhaps, the first step in the art of "synthesizing" drilling mud. It was a significant departure from the practice of relying solely on a circulating fluid whose properties were dependent upon the admixture resulting from the minerals unavoidably encountered in the course of drilling. The problem of maintaining a suspension of weighting material in the circulating fluid led, after trial and error, to the almost universal use of bentonitic clays as a mud additive. These minerals were added in quantities over and above the amount that might have been unavoidably encountered for the reason that they possessed "gel-like" characteristics in water and were found to stabilize the suspension of weighting material in water. At the same time, the art of using other types of clays to improve filter cake and viscosity characteristics must have been started. By the year of 1930, synthetic drilling muds took the form of "water-weighting material — bentonites —clays—stabilizing chemicals". Non-aqueous drilling muds, using oil as the dispersion medium in place of water, have been introduced but as yet have only special applications.

Many papers have been presented in the trade and the technical journals on the subject of drilling muds. Yet, it cannot be said that the literature on the subject provides a complete knowledge of the drilling mud art. A substantial amount of research remains to be done, particularly if broad scientific principles are to be established as a guide in the synthesis and control of drilling muds. The principle objective of mud research is to seek improvements for the purpose of reducing well drilling costs. Drilling costs involve a direct expense of the mud itself. Cost enters in a more important way, however, as an indirect cost of drilling. A "good" drilling mud permits substantial savings in drilling time and well completion. The indirect cost savings amount to sums large enough to justify increased investment in the formulation. control, and handling of "good" drilling mud if such a mud can be compounded.

● **Colloid chemistry and mud technology.** Drilling muds are colloidal systems. In recent years, the literature on the subject has stressed this fact in attempts to develop a technology of drilling muds. In some respects, the "colloidal" viewpoint has been over-stressed. The average technologist required to use and control drilling muds has found little guidance from the purported scientific explanations of what occurs from a physical and chemical point of view when barite, bentonite, clay, and other chemicals are mutually dispersed in water. The chemistry and physics involved lie in a field generally foreign to the interest, training, and experience of the average petroleum technologist. To even the more scientifically informed, drilling mud practices still remain an art rather than a technology derived from a well-defined field of science. Drilling mud improvement is still mainly a trial and error compounding. The field of colloidal chemistry provides only very broad rules for guidance. These statements are no criticism of those who attempt to apply the basic science. Rather, these statements are a criticism of the science of colloidal chemistry which has been disappointing in its failure to permit many immediately useful conclusions from the large and extended effort that has been made in that field.

The few broad principles that may be stated with some certainty in respect to systems represented by the dispersions of soluble and insoluble minerals comprising synthetic drilling muds may be summarized in the following statements. Drilling muds are suspensions of solids in aqueous solutions, and, like all colloidal dispersions, have a limited life. Such dispersions tend to separate into concentrated masses of their respective phases. The rate of separation (the life of the colloidal system) is determined by the particle size, the difference in specific gravity of the dispersed phase and the dispersion medium. and, the viscosity of the dispersion medium in conformance with fairly well established laws. The rate of separation is also determined in some measure by the chemical composition of the system. It is well known that drilling muds, like other such types of dispersions, have a short life in the presence of high concentrations of soluble electrolytes. Their sensitivity to electrolytes varies in an approximate relationship with the valency of the offending ion. It is also true that certain substances tend to impart prolonged life or stability. Bentonite stabilizes dispersions of barite and water if dissolved salt concentrations are low. Certain organic colloidal materials in the class of water dispersible starches and natural gums have been used or recommended as additives to stabilize mud dispersions in the presence of soluble salts.

● **Criteria of "good" mud.** Colloidal chemistry fails to be an effective guide in the control of drilling muds perhaps because it is the chemistry of complex systems. The chemistry of pure substances can be expressed by useful rules and principles. But, the chemistry of systems comprised of a wide variety of components substantially different in their pure chemical behavior, involves a complexity of reactions that lies beyond the realm of well-organized, and, intelligent knowledge. Certainly this statement

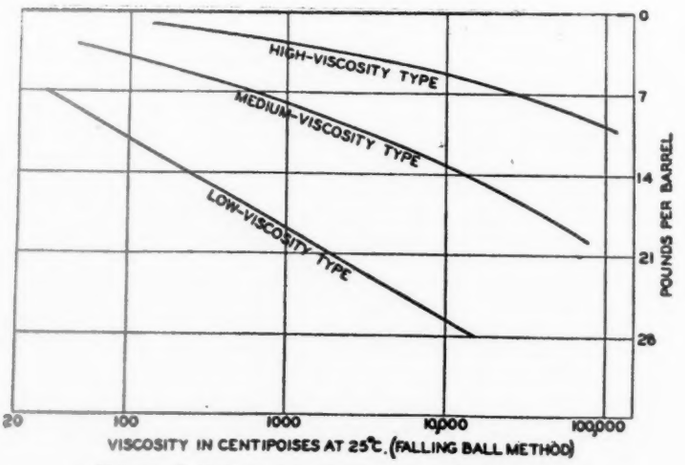


FIG. 1. Cellulose concentration in distilled water.

FIG. 3. Viscosity of drilling mud with different amounts and types of cellulose.

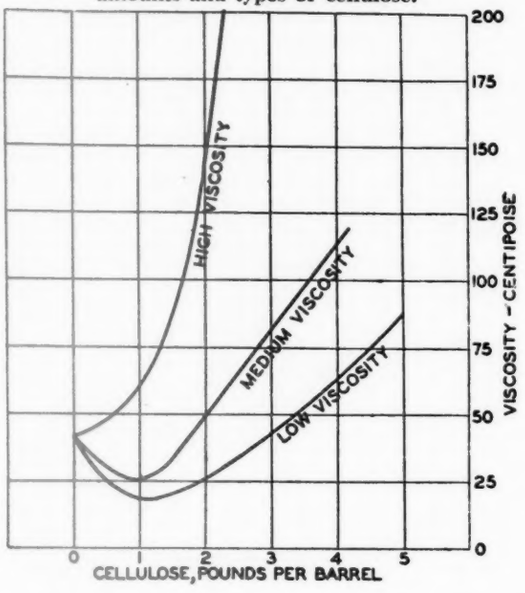


FIG. 2. (Right) Water loss behavior as function of cellulose content.

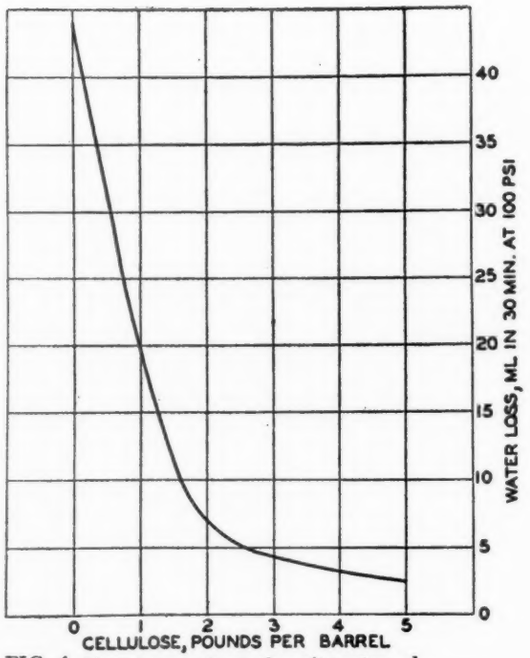
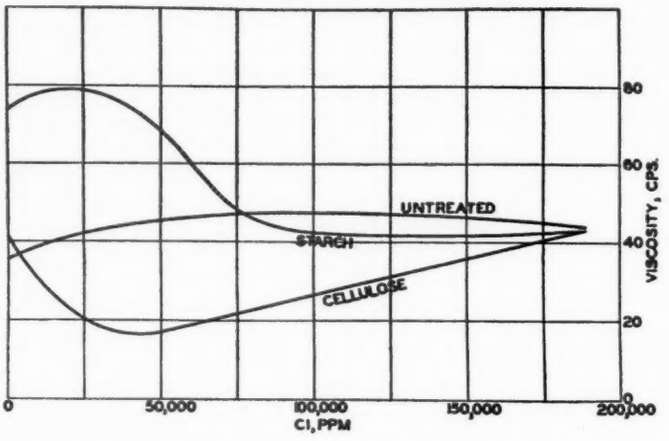


FIG. 4. Effect of salt on viscosity of mud.



applies to drilling muds so long as practical considerations of cost preclude an unlimited choice as to the composition of a circulating medium.

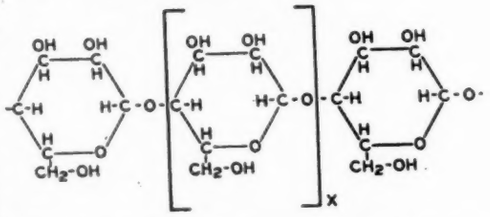
A "good" drilling mud should have the following properties:

1. Low viscosity compatible with pumpability and carrying capacity for cuttings.
2. Stability of the suspension of the weighting material, particularly in muds weighing more than 12 lb. per gal.
3. A high degree of thixotropy.
4. A thin, tough, filter cake of low permeability and of good deplastering quality.
5. Temperature stability.
6. High resistance to electrolytes.
7. Responsive to treating agents and control of properties.
8. Low electrical resistance.
9. Capacity to release larger size cuttings and release gas in the mud pit.
10. Non destructible by chemical or bacterial action.
11. Retards swelling of "bentonitic" or "heaving" shale.
12. Low initial and low maintenance cost.

Such a list of criteria for a "good" drilling mud is impressive by the fact that a drilling mud must meet a wide range and variety of uses and functions. Many materials and combinations of substances have been suggested as circulating fluids in rotary drilling operations in the effort to find muds that satisfy most of these requirements.

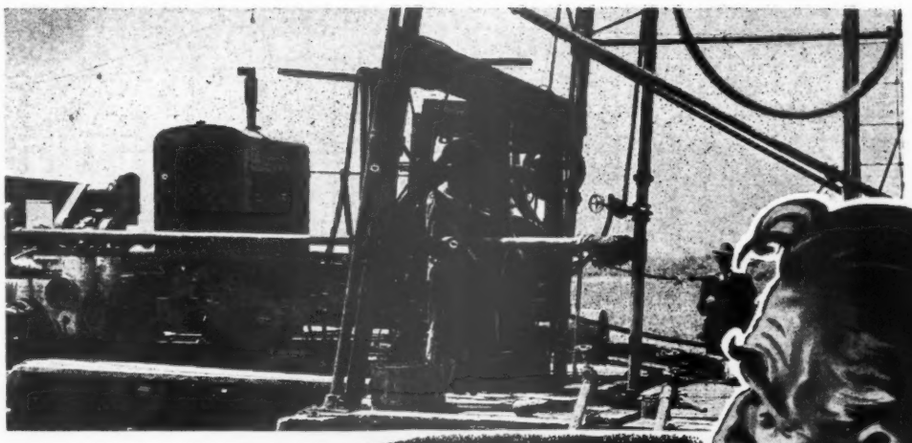
In view of the practical and economic limitations on the choice of compounds for drilling mud, researches were undertaken to seek improvement in the conventional aqueous drilling mud system. These researches led to the discovery that certain derivatives of cellulose, known as alkali metal carboxymethylcellulose, when added to the conventional aqueous drilling mud caused substantial improvement in all desirable characteristics. Mud containing alkali metal carboxymethylcellulose showed superior properties to any heretofore used. The sodium salt is the cheapest alkali metal salt, and, for that reason, it is the salt of carboxymethylcellulose which will be used commercially.

● **Water dispersible cellulose.** Cellulose is the main and principle constituent of the woody parts of plants. Cotton is almost a pure form of cellulose, and, the basic character of the material is therefore well known. The chemical structure of cellulose may be represented by the following formula:



It is a very large molecule. The glucose unit indicated by the sub-script "X" in the formula recurs more than 200 times in the molecule.

Cellulose is insoluble in water. It is, however, soluble in alkali, such as a 40 per cent aqueous solution of sodium hydroxide. In alkaline solution, the cellulose molecule is split into smaller units. The degree of splitting depends upon temperature, time, concentration of oxy-



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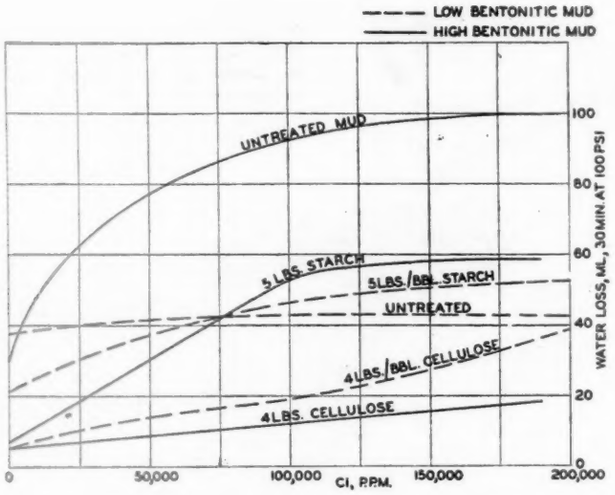


FIG. 5. Effect of salt on water loss values.

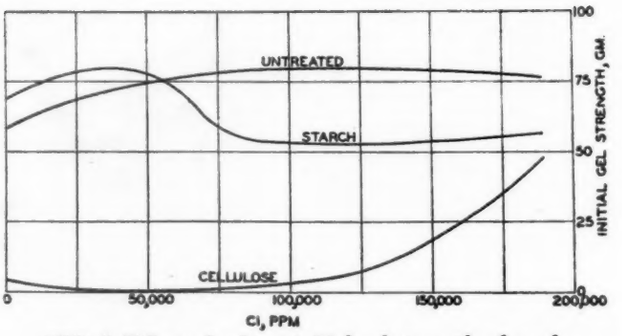


FIG. 6. Effect of salt on initial gel strength of mud.

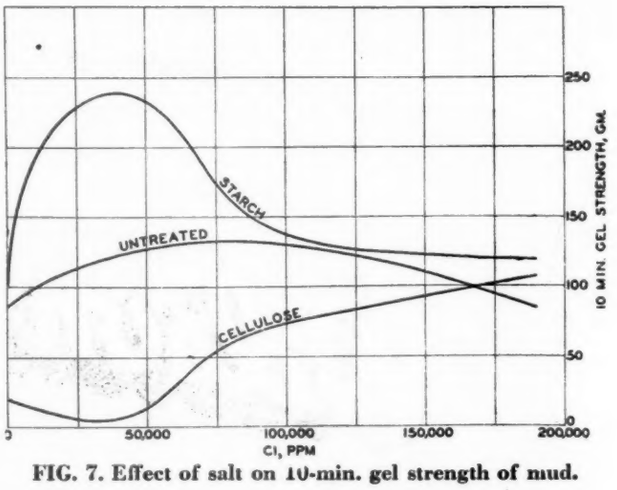


FIG. 7. Effect of salt on 10-min. gel strength of mud.

FIG. 9. Comparison of effects of cellulose with natural gums.

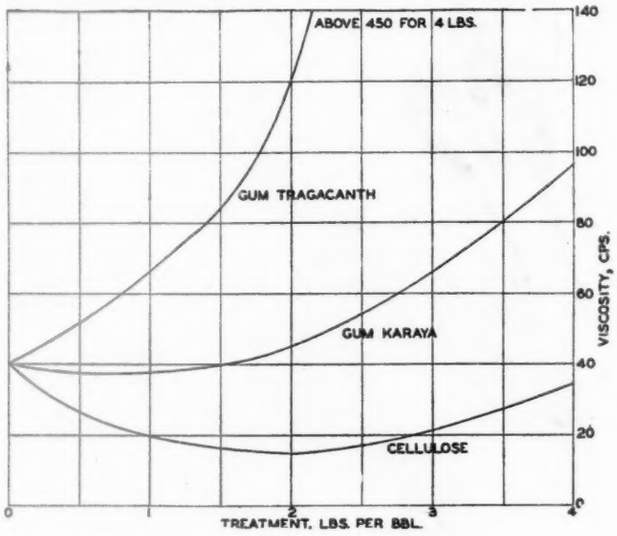
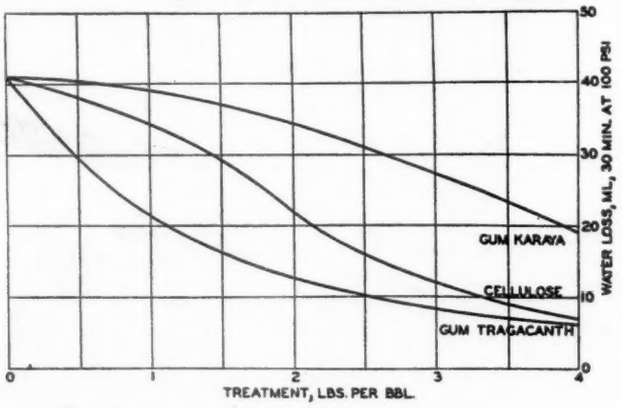
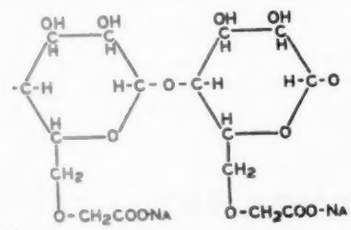


FIG. 8. Comparison of cellulose with natural gums.



gen, and, concentration of caustic. The splitting reaction is the first step in rendering cellulose suitable for use in drilling mud. If the sodium cellulose formed by solution in caustic soda is treated with mono-chloracetic acid ($ClCH_2COOH$), a substitution occurs first on the primary hydroxyl group, and, if the reaction is allowed to proceed further, next upon the secondary hydroxyl groups, in such a manner as to yield a glycollic ether. When only the primary hydroxyl groups are reacted, the product carboxymethylcellulose is as follows:



This is the second step required to render cellulose suitable for use in drilling mud. The compound in this example is sodium carboxymethylcellulose. It is a white, granular, odorless, and tasteless powder having a specific gravity of 1.7.

The maximum substitution possible is three hydroxyl groups per glucose unit. If the substitution of the type shown is as much as 0.4, the sodium carboxymethylcellulose is water dispersible.

● **Important properties of water dispersible cellulose.** The free glycollic acid is insoluble in water but is soluble in alkaline solution. The alkali metal salt is the preferred form for use in drilling mud because it is readily dispersible in water. A point of interest in this connection is that the alkali metal salt of carboxymethylcellulose is an electrolyte, whose anion is large enough to fall within the colloidal classification of size.

One of the outstanding characteristics of alkali metal carboxymethylcelluloses is their power to impart high viscosity to aqueous solutions. The degree of viscosity imparted to water solution depends upon molecular size as determined by the degree of splitting in the mercerization reaction, as well as upon the degree of substitution. For commercial application, such compounds can be prepared in a wide range of viscosity characteristics usually referred to as high, medium, and low range. The viscosity behavior in water is summarized by the data given in Fig. 1 for the three ranges of viscosity type of sodium carboxymethylcellulose.

Another outstanding characteristic of alkali metal carboxymethylcelluloses is that they possess heat stability in aqueous solutions. Moreover, the viscosity of aqueous solutions show only a very slight reduction with temperatures as high as 212° F.

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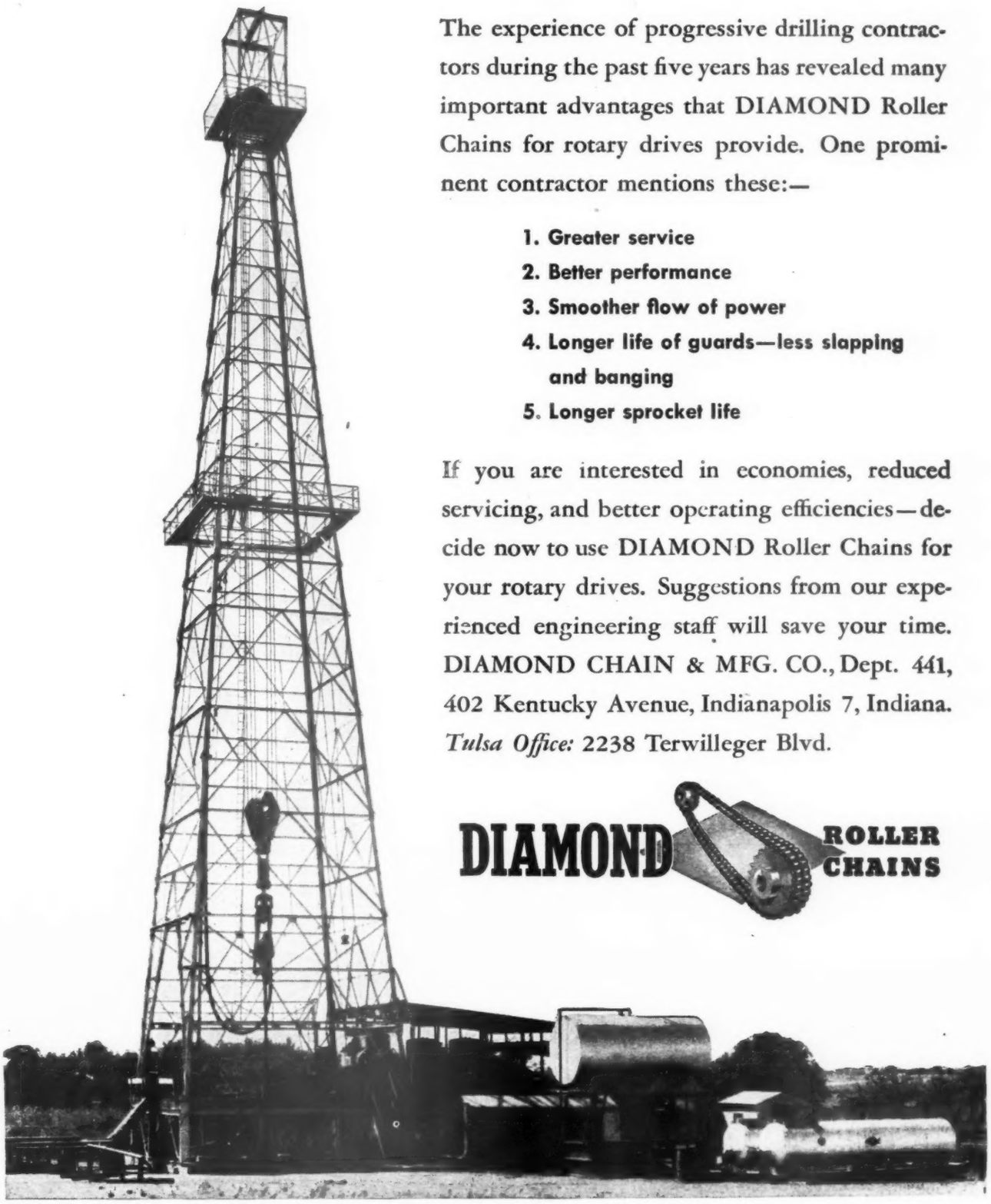

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Alkali metal carboxymethylcelluloses are immune to bacterial or enzymatic action. They do not ferment under conditions of use in drilling muds. Mold growth occurs only under very special and controlled conditions.

Alkali metal carboxymethylcelluloses are not precipitated by salts in solution except for those salts that may be classified as the polyvalent amphoteric type, in the class of aluminum, lead, iron, tin, and copper. Of particular interest is the fact that calcium ion does not precipitate carboxymethylcellulose except from solutions nearly saturated with a calcium salt such as calcium chloride. This is important in connection with drilling muds in view of the resistance of anhydrite and cement contamination that the alkali metal carboxymethylcellulose imparts.

Cellulose derivatives of the type being discussed, have been known for at least 25 years. They were industrial products in Germany during World War I. They have found a wide variety of uses ranging from application in the manufacture of crayon through a long list to include even the baking industry. No application of the material, however, is more interesting, nor more important, than that which resulted from the discovery of the pronounced beneficial effect of the cellulose derivatives in drilling mud. Perhaps no useful application of the material was more unexpected.

● **Properties of muds containing carboxymethylcellulose.** Researches involving a detailed laboratory appraisal have been completed and a number of wells have been drilled using sodium carboxymethylcellulose as a drilling mud additive. Experience and technical data developed to date indicate that sodium carboxymethylcellulose imparts superior characteristics to aqueous drilling muds. Its use has permitted a substantial reduction in direct mud costs. Beyond this, the good mud characteristics, and ease of mud control when it is used, has permitted substantial indirect savings in drilling and completion costs.

The general properties of the sodium carboxymethylecllulose mud are summarized as follows with the information presented based entirely upon the generally accepted test procedures of API Code 29:

1. Water loss. Sodium carboxymehtylcellulose imparts to all varieties of aqueous drilling muds a low water loss in the standard filter press test. Standard water losses in the range of 3 to 4 cc per 30 min. can be obtained and maintained. The general result obtained in respect to this property is shown by Fig. 2. Low water loss values can be maintained in the presence of high concentrations of soluble salts.

2. Filter cake thickness. Filter cake characteristics of drilling mud with sodium carboxymethylcellulose are consistently in the range of 2/64-in. to 3/64-in. thickness.

3. Viscosity. In spite of the marked effect of sodium carboxymethylcellulose in increasing the viscosity of water, it was surprising to discover that in drilling muds the viscosity increase of sodium carboxymethylcellulose is not excessive. In many instances, the viscosity of the mud is reduced. The viscosity resulting from the use of sodium carboxymethylcellulose depends somewhat upon the quantity of bentonites and non-bentonitic type clays present. The general behavior is represented by Fig. 3.

Viscosity control in useful operating ranges can be maintained in the presence of sodium carboxymethylcellulose, even when salt content is high. The general behavior in this respect is shown in part by Fig. 4.

4. Gel strength. Low gel strengths can be consistently obtained and maintained in drilling mud by the use of sodium carboxymethylcellulose. In any event, the thixotropic ratio, measured as the ratio of the 10-minute gel strength to the initial gel strength, is usually increased by the use of sodium carboxymethylcellulose. This is a very desirable condition. Gel strengths, however, depend upon the quantity and type of clay present. High bentonitic content muds show less decrease in gel strength than do those having high non-bentonitic type clay content. It is, however, quite possible to maintain initial gel strengths in the range of 0 to 5 grams by the standard Stormer test, and 10-min. gel strengths in the range 20 to 40 grams, for any mud if salt concentrations are less than 75,000 p.p.m.

5. Resistance to salt flocculation. Sodium carboxymethylcellulose has a remarkable ability to stabilize drilling muds in the presence of even high concentrations of soluble salt. This is particularly true in the case of sodium chloride and calcium salts, commonly encountered in the drilling operation. In this respect, sodium carboxymethylcellulose renders the mud truly salt water resistant. In the presence of soluble salt, low water loss can be maintained while

FIG. 10. Average daily drilling rate in feet per day for 3000-ft. wells, Hugoton field. (Approx. top of massive anhydrite section, 2100 ft.)

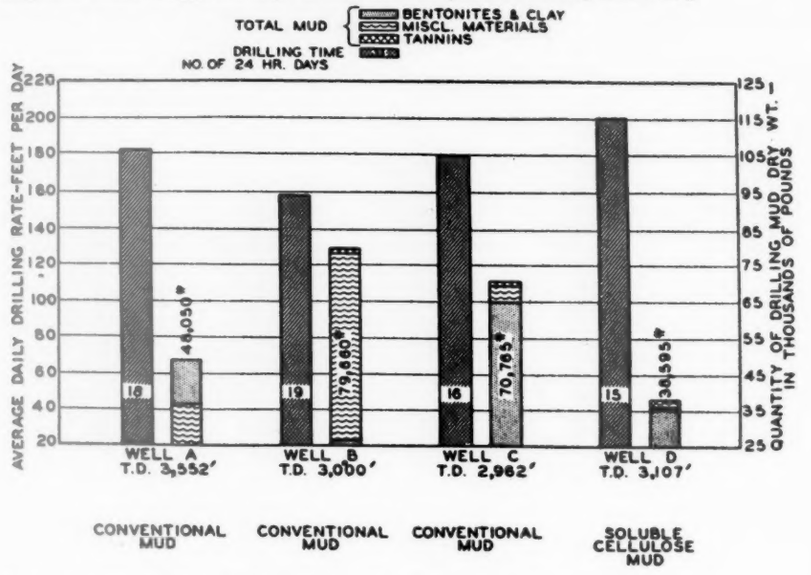
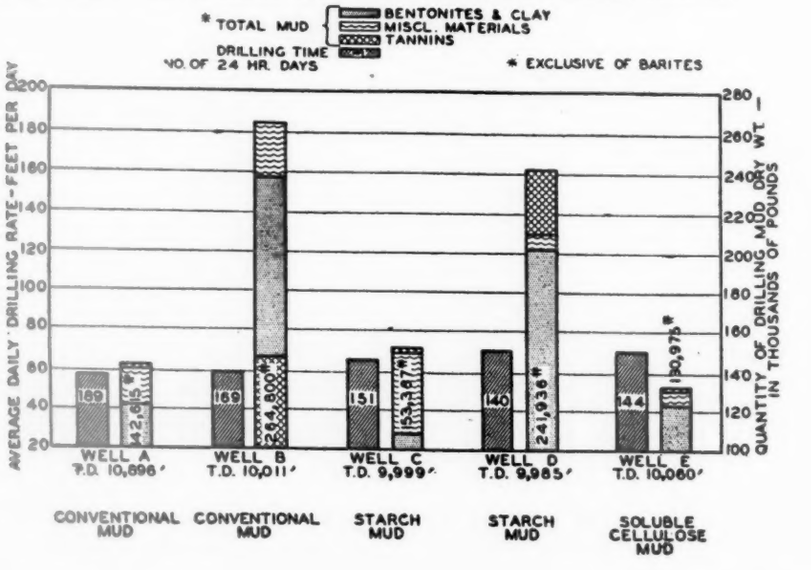


FIG. 11. Average daily drilling rate in feet per day for 10,000-ft. wells, South Tyler field. (Approx. top of massive anhydrite section, 9300 ft.)



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viscosity and gel strengths can be readily maintained in acceptable and useful ranges. The effectiveness of sodium carboxymethylcellulose in respect to its salt resistance is shown by the information given in Figs. 4, 5, 6, and 7, respectively, wherein salt was added to the salt-free mud. Resistance to salt concentrations in respect to all properties is improved if salt is added or is present in the drilling mud before the sodium carboxymethylcellulose is added.

Experience indicates that salt and anhydrite sections can be drilled without the treating problem encountered with either conventional or starch base muds. Conditions may be encountered where some treatment would have to be given for the presence of soluble calcium ion to reduce viscosity of the mud. If that is required, the conventional methods for removing calcium can be relied upon.

● **Comparison with starch and natural gum.** In recent years, water dispersible starch has been widely used as a drilling mud additive for the particular purpose of maintaining mud properties in the presence of high salt concentrations in the mud. Natural gums have been suggested as additives for mud for the same purpose. A summary of comparative tests of starches and gums as compared to sodium carboxymethylcellulose is given in Figs. 4, 5, 6, and 7, for starch, and, in Figs. 8 and 9 for natural gums, indicating that sodium carboxymethylcellulose possesses superior properties to either starch of gum in the compounding of salt resistant drilling muds. Sodium carboxymethylcellulose has many distinct advantages over both starches and gums beyond maintaining superior mud properties in the presence of high salt content. Sodium carboxymethylcellulose is not fermentable and is not subject to enzyme action. Sodium carboxymethylcellulose does not require maintenance of high pH since its range of usefulness lies at any point above 7.5. Sodium carboxymethylcellulose muds are stable at all temperatures encountered in drilling. Natural gums deteriorate too rapidly and give such high viscosities in mud as to cause them to be not very useful.

Sodium carboxymethylcellulose is different in chemical structure from starch or gums, and, the comparison made here with starch and gums is given merely for the purpose of comparing its properties in drilling muds with those of starches and gums.

● **Heaving shale.** Laboratory tests have demonstrated that bentonite and bentonitic minerals show little tendency to swell in contact with water dispersions of sodium carboxymethylcellulose. In fact, if moderate quantities of salt are present in solution with carboxymethylcellulose, the tendency to swell in contact with water that bentonite possesses is almost completely repressed. At the present time, a program of well drilling in areas underlain by thick shale sections is going forward. In due course, field experience will be had to determine whether or not the sodium carboxymethylcellulose mud will be effective in overcoming the difficulties of drilling in "heaving shale".

● **Summary of well drilling experience.** Considerable experience in well drilling in areas underlain by either or both salt and anhydrite sections has been obtained. Such experience shows clearly that sodium carboxymethylcellulose muds permit substantial savings in direct mud cost and result in savings in drilling time.

In Fig. 10, experience in drilling wells in the Hugoton gas field is summarized. Weighting material was not added to the drilling mud in these operations. These wells were all drilled in immediately adjacent areas under drilling conditions that otherwise appeared to be quite comparable. The well drilled with sodium carboxymethylcellulose mud showed as high a rate of drilling and required substantially less quantity of drilling mud materials than other wells drilled with conventional mud. The conventional muds were subjected to various types of treatment and composition in an effort to improve and maintain good quality. The sodium carboxymethylcellulose mud requiring little if any treatment was in all respects superior to conventional muds used. The short drilling time required for these 3000-ft. wells does not permit definite conclusions as to whether or not the sodium carboxymethylcellulose mud actually resulted in any significant decrease in time of drilling. The salt section penetrated in these wells is approximately 800 ft. thick in the interval 2000 ft. to 2800 ft. in depth (Well D).

In Fig. 11, a summarized experience in the drilling of 10,000-ft. wells in the South Tyler field, Smith County, Texas, is given where two wells were drilled with conventional mud, two with starch-base mud, and one with sodium carboxymethylcellulose mud. The "weight of mud used" is exclusive of the weights of barite for the purpose of showing the quantities of clay and treating chemical required. The weighting material required for all wells was approximately the same. In the South Tyler field, anhydrite stringers are encountered in the interval 8900 ft. to 9100 ft., while a 250-ft. anhydrite section occurs in the interval of approximately 9300 ft. to 9550 ft. The usual practice is to carry 13½-lb. mud to approximately 9400 ft., and 14½-lb. mud to total depth. Sodium carboxymethylcellulose mud was used from a depth of 6000 ft. after surface pipe was set. The average characteristics of the sodium carboxymethylcellulose mud, other than the weight just given, that were maintained below 6000 ft. were: water loss: 5 cc per 30 min.; pH: 8.0; 10-min. gel-strength: 40 grams; initial gel-strength: 0 to 10 grams; and viscosity 65 c.p.s.

Advantages in the use of sodium carboxymethylcellulose mud are reflected by the substantially lower requirements for treating chemicals. The actual drilling time for the sodium carboxymethylcellulose mud compares favorably with the best rate of drilling achieved with any other type mud.

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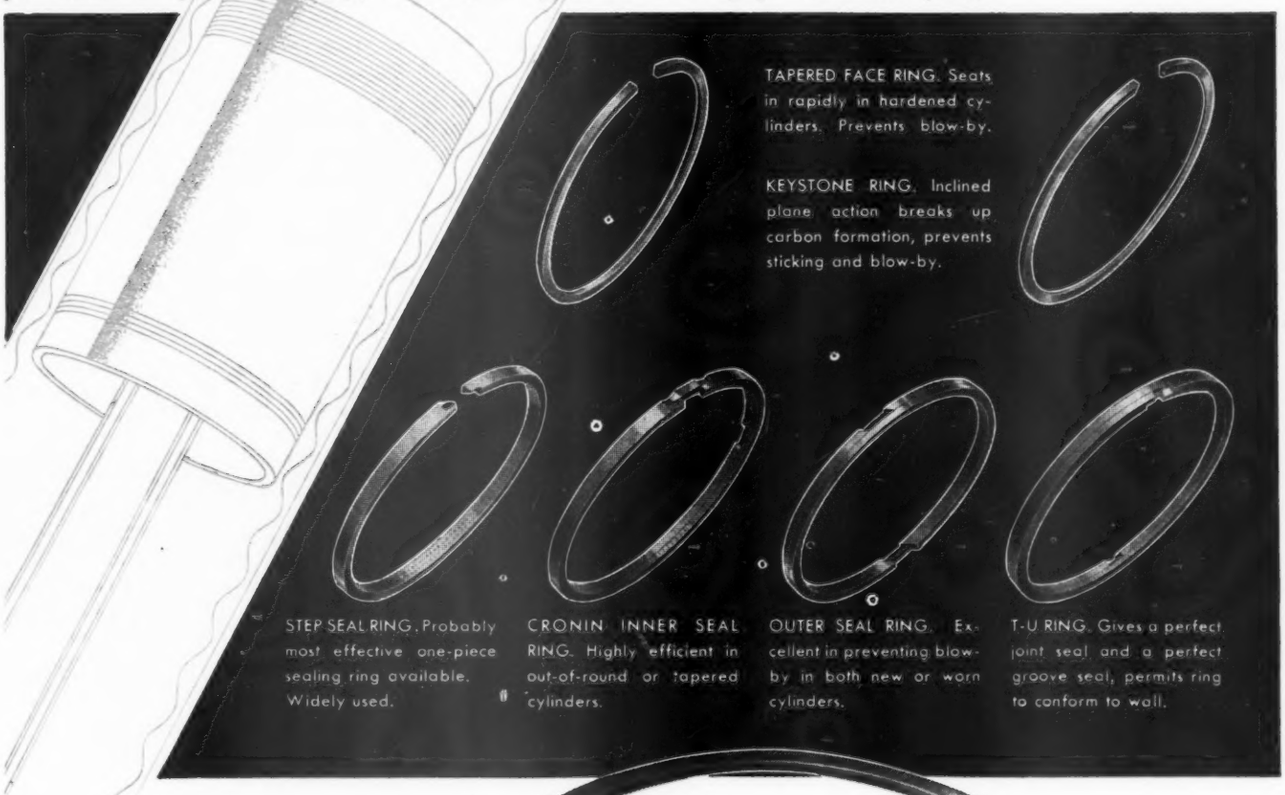
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boxymethylcellulose mud observed during the course of well drilling may be referred to briefly: Low initial gel-strengths obtainable cause the muds to readily release entrained gas, and, to drop cuttings in the mud pit rapidly. The mud responds readily to treating agents and is, therefore, not subject to overtreatment with resultant detrimental effects. The sodium carboxymethylcellulose mud shows an unusual ability to carry weighting material when weights of 13 to 15 lb. per gal. are necessary.

● **Method of handling sodium carboxymethylcellulose.** The use of sodium carboxymethylcellulose in drilling mud involves no special procedures nor special equipment. The material is a non-hygroscopic solid that can be shipped in paper bags, stored and handled in the same manner as other mud components. The material goes into solution readily, but, should be introduced with thorough stirring. This is most conveniently accomplished by using a vacuum type hopper to introduce the material into the mud stream at a uniform rate. The sodium carboxymethylcellulose operates most efficiently in the presence of some salt concentration in the general range of 20 to 30 thousand parts per million of salt. If the sodium carboxymethylcellulose is used to counteract additions of salt or anhydrite to the mud, the best practice is to add the sodium carboxymethylcellulose before such additions occur. The quantity of sodium carboxymethylcellulose required varies with existing conditions and lies in the range of 1 lb. to 4 lb. per bbl. The usual quantity is 2 lb. to 3 lb. per bbl.

The present supply of sodium carboxymethylcellulose for use in drilling mud is quite limited, but, it may be expected that some quantity of material will be available in the last quarter of 1946. It is expected that a supply sufficient to meet the demands of the industry will be available in 1947.

● **Summary.** Field and laboratory experience has established that alkali metal carboxymethylcellulose imparts superior qualities to aqueous well drilling mud comprising the system: water plus dispersed fine mineral solids. Improvement in all of the desirable properties of such muds, more particularly in water loss, filter cake thickness, gel-strength, viscosity, salt water resistance, and freedom from fermentation, is obtained. Cellulose is an economical material to use in drilling muds and its use results in substantial savings in direct mud costs, as well as savings in drilling and completion costs. This is particularly true of drilling in areas underlain by salt and anhydrite sections.

● **Acknowledgement.** This report is a joint effort on the part of many on the staff of Phillips Petroleum Company. C. R. Wagner was responsible for outlining the original research program. Members of the drilling mud section of the drilling tool division and of the production research section of Phillips Petroleum Company contributed to the research and development of the sodium carboxymethylcellulose mud. ★★★

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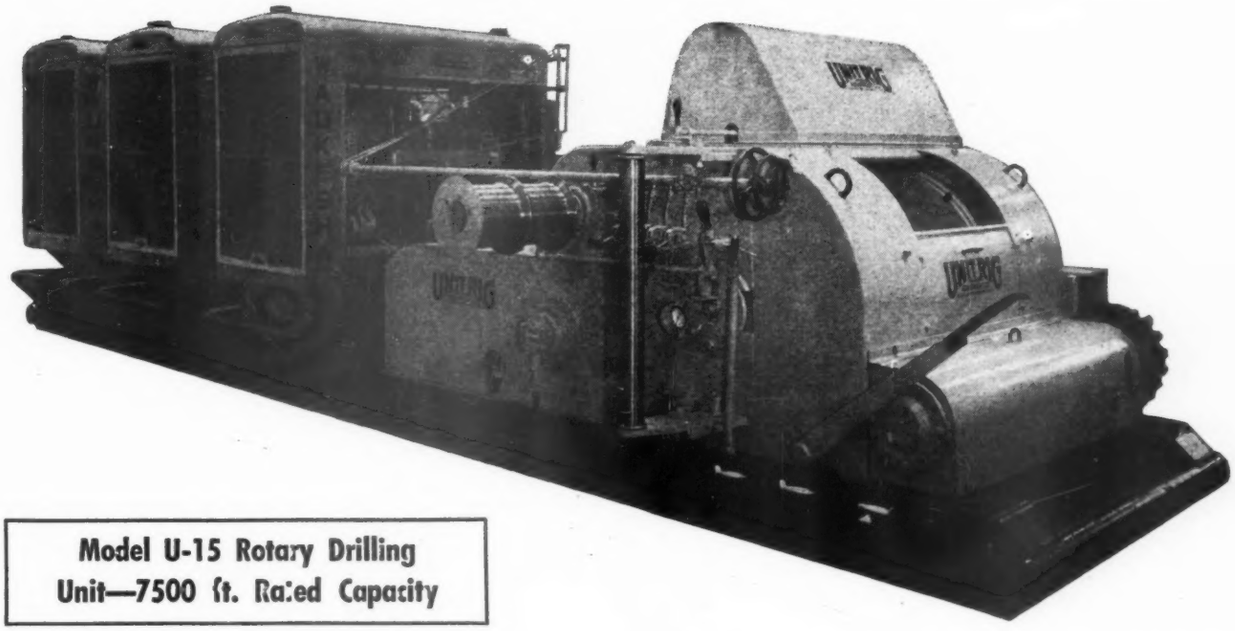

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Casing Landing Practice*

By **JOHN P. DE HETRE,** *Field Engineer*

The Youngstown Sheet and Tube Company

● **Abstract.** The advancement of casing program design technique is pointed out in contrast to a lack of corresponding improvement in landing practice. It is suggested that individual attention be given to each well in a new field until enough information is available to warrant adoption of a standard procedure.

Long oil strings and long intermediate protective strings are presented as being the most hazardous and particular attention is directed to the necessity of keeping their landing weight to a minimum consistent with the other factors involved.

Several common landing methods are discussed, showing their weaknesses under certain conditions.

A chart is presented to show a method of determining depth to the freeze point.

Another chart shows a method of evaluating the effect on the load at the landing head of pressure and temperature changes.

An example procedure is worked out to show the need of engineering consideration of the landing problem.

The conclusion that the landing weight of long strings should be held to a minimum is emphasized by reference to API data on bi-axial loading, which shows a substantial reduction of the resistance of casing to burst and collapse when tensile loads are more than half the yield strength of the pipe.

● **Introduction.** There have been many refinements during the past few years in the methods of casing program design. All these improvements have been aimed at tapering casing strings so that a greater percentage of the pipe that is set in the hole is subjected to the maximum allowable stress. This is especially true in long strings of casing since there are practically no operators today that use less than three kinds of pipe in casing strings longer than 8000 ft. and they may use as many as five or six different weights and grades. To match this development in casing program design, it is questioned whether there has not been a corresponding advancement in landing practice technique. Many old methods that were conceived when wells were only a fraction of their present depths are still being used. However, it would be difficult to make a definite statement that certain ones of these methods are unsatisfactory for particular cases. If more of the failures that have occurred in landed strings of casing could have been retrieved for examination, there is reason to believe that a portion of them could be attributed to an overstressed condition that developed after the pipe was landed.

Although practically all operators now figure their casing programs much closer than they did seven or eight years ago, and they have devoted a considerable amount of engineering thought to program design methods, still a great many of them leave the matter of arriving at a proper landing procedure to the man in the field who, in many cases, does not know the margin of safety that is available in the casing program. He, also, may not know the pressure and temperature conditions that may be created by future production methods. It is probably true that a standard procedure of landing pipe can be set up for a particular field where conditions are well known, but it is seriously doubted if any one method can be set up that will be entirely satisfactory to an operator who is drilling in many fields where wide ranges of depths, pressures, and temperatures are encountered. It is therefore believed that the discussion to follow will show the desirability of giving adequate engineering consideration to casing landing procedure for individual wells in new fields until enough is known about the area to establish a standard method.

Because of the assumptions affecting landing procedure that must be made in drilling the first well in a new area are subject to such wide variation, it would not be worthwhile to base concise calculations upon them; but as information is developed, more accurate figures can be made to bring the landing stresses to a minimum. The greatest hazards associated with variations in landing methods occur in long oil strings and protective strings where the safety factors are low and pressure and temperature changes are most apt to be severe. It is with these long strings and a method to aid in arriving at a minimum landing weight consistent with safety that the remarks of this paper are most concerned.

● **Existing landing methods.** Listed below are several representative landing methods that have been used:

(1) The casing is landed at the exact position it occupied while standing cemented.

(2) The casing is landed with a weight that is a certain arbitrarily chosen percentage (a) in excess of or (b) less than the measured weight of the pipe just prior to cementing.

(3) The casing is landed with a certain number of inches (a) stretch or (b) slack per 1000 ft. of casing length, measured from the free hanging position while standing cemented.

In most cases the pipe is allowed to stand cemented for at least six hours and many operators wait 24 hours before landing their casing. Recent work[1] has shown the necessary waiting-on-cement time from a strength standpoint to be approximately 10 hours maximum. This amount of time is also shown to be sufficient for the cement to reach its maximum temperature. There are some operators that land their casing as soon as the cement is put away. They, of course, must land the pipe with its full weight, allowing any subsequent temperature or pressure changes to change the load at the head. The matter of temperature and pressure changes will be discussed at more length later.

One danger associated with method (1) occurs when the pipe is rested on bottom to allow the removal of blowout preventers and other equipment prior to landing. In this case the freeze point may move upward while the casing is in compression, and later when an attempt is made to bring the pipe to its original position for landing, a greater stress is induced in the free casing because a shorter length of pipe is stretched the same total amount. It is possible that excessive tensile stresses can be induced by this method, and the operator should watch his weight indicator carefully to ascertain that he does not pull more than the total weight of the pipe before it was cemented.

Another danger accompanying this method is particularly pronounced in deep gas and condensate wells where bottom hole chokes are used. In this instance an excessive temperature drop may cause a large increase in the tensile loading at the landing head. This load increase caused by a temperature drop added to an already large tensile load of a long casing program can induce stresses of a dangerous magnitude in the upper lengths of pipe.

Each of the other listed methods can also be the cause of trouble under certain conditions, and consequently it is felt that none of these should be used arbitrarily, but they should be varied according to the well. As an example, method (2a) could cause trouble from excessive tensile stress if the over-pull happened to be in excess of the margin of safety for a particular weight and grade of pipe in the string. This is most likely to be the case when a lower grade of casing is used below the top section in the program. This circumstance indicates that the designers of the casing program should always have a hand in establishment of landing procedure.

Method (2b) might conceivably cause a bottom portion of the free casing to be in compression (too much slack) if the actual freeze point of the pipe were to be established at a deeper than anticipated point prior to landing the pipe. This condition is most apt to be dangerous when long protective strings are set and considerable drilling is done through the casing. In this case the drilling mud from the deeper hole will be hotter than that in the pipe when it was landed, and this increase in temperature will increase the slack.

Method (3a) might induce excessive tensile stresses, especially when the freeze point moves upward, and method

*Presented before American Petroleum Institute Pacific Coast District Division of Production, Los Angeles, April 12, 1946.

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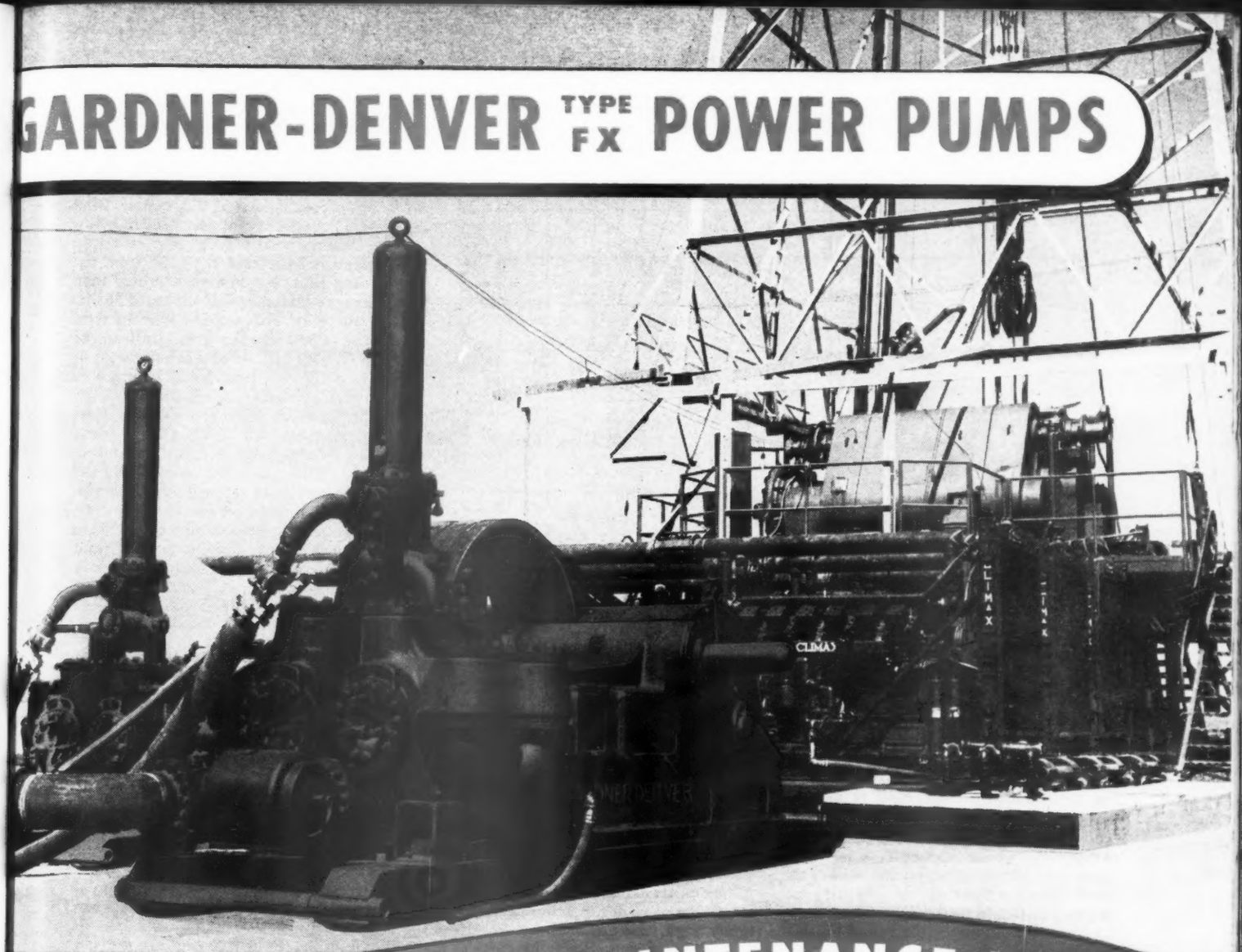

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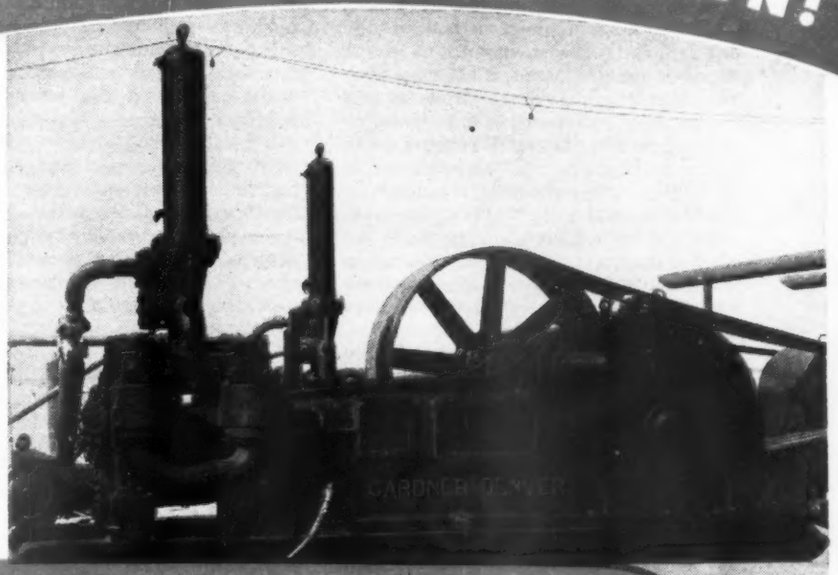

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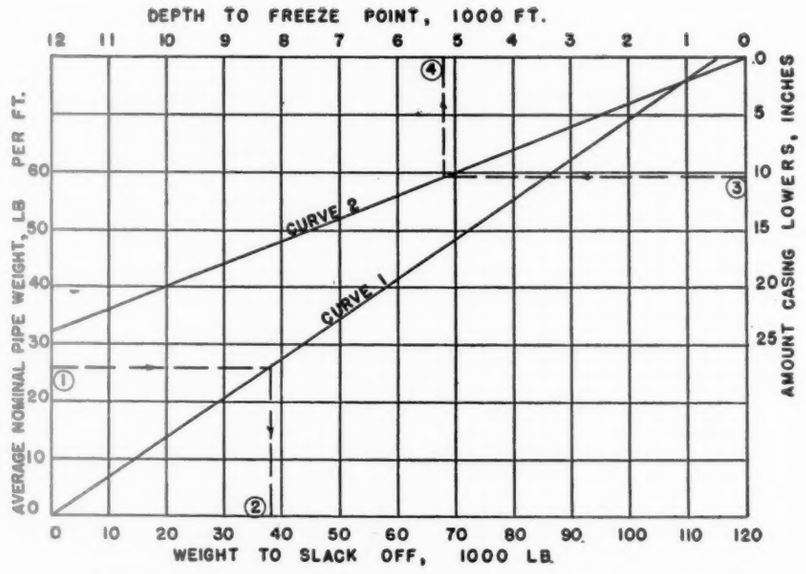

DEPTH TO FREEZE POINT, 1000 FT.
12 11 10 9 8 7 6 5 4 3 2 1 0
AVERAGE NOMINAL PIPE WEIGHT, LB PER FT.
0 10 20 30 40 50 60
AMOUNT CASING LOWERS, INCHES
0 5 10 15 20 25
CURVE 2
CURVE 1
1
2
3
4
0 10 20 30 40 50 60 70 80 90 100 110 120
WEIGHT TO SLACK OFF, 1000 LB.

FIG. 1. Chart for determining depth to freeze point of casing strings.

(3b) might cause the pipe to be too slack if the freeze point were higher than expected. Consequently, it is not believed to be advisable to use any method involving definite increments of stretch or slack because the resulting stresses then become a function of the depth to freeze point, an uncertain and changing figure.

● **Location of freeze point.** In all discussions concerning casing landing procedure the location of the freeze point becomes a major factor. This is occasioned by the fact that no one wishes to land casing without all the free pipe in tension. It should be stated that the effect of buoyancy of the drilling mud on the weight of the free pipe should not be considered when the lower end of the casing is constrained as when it is cemented or otherwise anchored in hole.

If all casing landing methods involving arbitrarily chosen amounts of stretch or slack are eliminated, it becomes obvious that the maximum depth to the freeze point becomes the important consideration. The phrase "Maximum depth to the freeze point" is used because it is generally considered that the depth of the freeze point will eventually move upward to the approximate depth of the shoe of the next larger casing size, and in many fields this change of freeze point is known to take place in a matter of days or even hours after the pipe is landed. Therefore, if the pipe is landed with sufficient tension to assure the operator that the maximum amount of free pipe will be in tension, the stress on the top joint will not change with subsequent upward movement of the freeze point.

J. T. Hayward[2] pointed out that stretch increments of frozen pipe for known amounts of pull can be used to calculate the depth to the freeze point of a frozen string. The convenient chart of Fig. 1 has been developed for use in determining the freeze point in the field. This chart is based on a stress reduction of 5000 lb. per sq. in. in the free pipe. Curve 1 is a graphical solution of the equation.

$$P = 1445\,W \text{ (a)} \quad . \quad . \quad . \quad . \quad . \quad . \quad (1)$$

Where: P = load, to slack off, lb., and W = average nominal pipe weight above freeze point, lb. per ft.

Curve 2 is a graphical solution of the the equation.

$$L = 500 \triangle L \text{ (a)} \quad . \quad . \quad . \quad . \quad . \quad . \quad (2)$$

Where: L = depth to freeze point, ft., and $\triangle L$ = amount casing lowers, in.

(a) See appendix for derivation.

The application of this chart will be explained in the example later. Because this chart employs a reduction in load its use is recommended particularly for long strings where tensile loads are already high, and any increase in stretch may be dangerous. Since the curves are based on a stress change of 5000 lb. per sq. in., the chart may also be used for added tension if this should be desirable in shorter strings. It should be stated at this point that the success of any method involving weight increments depends almost entirely on the accuracy of the weight indicating equipment, and unless this equipment is accurate within 5 per cent, the results obtained would be of insufficient value to warrant the effort. In the event that the weight indicator is unsatisfactory, the cement point can be determined by a temperature survey checked by cement displacement figures provided the calculator is conservative and establishes his estimate on the deep side so the resulting landing weight will be in excess of the weight of free pipe.

Concerned with the matter of change in freeze points is the problem of removing casing from the landing slips when remedial work is necessary on the well. If a 10,000-ft. string of 7-in. casing consisting of 1700 ft. of 29-lb. N-80, on bottom and 8300 ft. of 26 lb. N-80, with long couplings on top is landed with the full pipe weight, 225,000 lb., prior to cementing, the tensile stress in the top length of pipe will be approximately 30,000 lb. per sq. in. and the safety factor on the pull-out strength of the couplings will be 2.05. These figures are based on the total weight of the casing, taking into account the effect of buoyancy of 72 lb. per cu. ft. mud, since the weight prior to cementing would be affected by the buoyancy.

If the freeze point of this casing string should move to a point only 1000 ft. below the landing head and it requires a 1 ft. movement to release the pipe from the landing slips, this movement would then induce an added tensile stress of 30,000 lb. per sq. in. This would cause the total tensile stress in the pipe wall to be 60,000 lb. per sq. in. or a safety factor of 1.33 on the minimum yield strength of the pipe wall. Stretching this 1000 ft. of 26-lb., N-80 Casing, 1 ft. would require an over-pull of 225,000 lb. or a total pull of 450,000 lb., which would result in a safety factor of only 1.02 on the minimum pull-out value of the couplings.

These figures do not consider any average change in temperature or pressure from those at the time of landing, and are pointed out to show that trouble may be encountered when remedial work is attempted, especially if too much tension is applied to the pipe when landed.

● **Effect of pressure and temperature.** Once the pipe is frozen at the bottom and anchored at the top the only important causes of stress changes are temperature changes, pressure changes, and earth movement. If the average temperature and pressure changes to which the free pipe is subjected are considered, the effect on the weight at the landing head is not a function of the length of free pipe.

The stress induced by earth movement when the pipe ends are constrained is dependent upon the distance between anchor points, decreasing with an increase in length of free pipe for a given amount of movement; but it has been the experience of most operators that if an earth movement of importance occurs, it is useless to consider that any casing program will withstand the resulting loads. As a result, the matter of stresses resulting from earth movements will not be dealt with in this paper.

Cases have been noted where pipe has moved upward in the landing slips because of the injection of high temperature gas into the casing. This same upward movement has occurred in wells where high pressure gas was introduced into the annulus outside the casing in question. In each case the elongating effect of temperature and external pressure was sufficient to overcome that created by the tension that was applied when the pipe was landed. Because of these lengthening conditions, added tension must be applied at the landing head to compensate for them when their existence is anticipated.

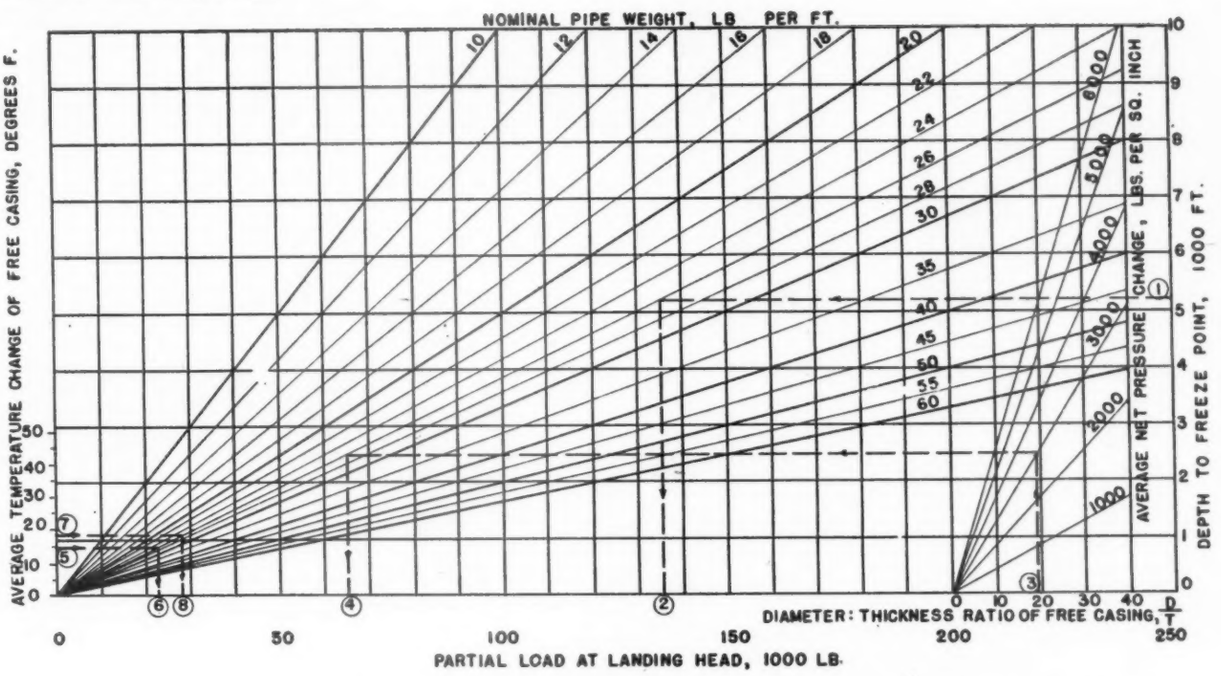
The chart of Fig. 2 has been developed as an aid in evaluating the effect of temperature and pressure changes on the load at the landing head. The section of chart devoted to temperature change is a graphical solution of the equation.

$$P = 58.2\,W \triangle T \text{ (a)} \quad . \quad . \quad . \quad . \quad . \quad (3)$$

Where:

P = change in load at landing head, lb.,
W = nominal pipe weight, lb. per ft.,

FIG. 2. Landing weight chart.



$\triangle T$ = average temperature change of free casing, ° F.

When the temperature change is a drop, the effect at the landing head is an increased load; and when the temperature change is a rise, the effect is a decreased load.

The section of the chart which has to do with pressure change is a graphical solution of the equation.

$$P = 0.0434\ W \triangle p \frac{D}{t} \text{ (a)} \quad . \quad . \quad . \quad (4)$$

Where:

P = change in load at landing head, lb.,
W = nominal pipe weight, lb. per ft.,
$\triangle p$ = average net pressure change in free pipe, lb. per sq. in.,
D = pipe O.D., in., and
t = pipe wall thickness, in.

(a) See appendix.

If the average net pressure change is an external increase, the effect at the landing head is a decreased load, and if the pressure change is an external decrease (internal increase), the effect at the landing head is an increased load.

Fig. 2 also provides a graphical method of arriving at the weight of the pipe above the estimated freeze point. This section of the chart is a graphical solution of the simple equation.

$$P = W L \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (5)$$

Where:

P = weight of pipe above freeze point, lb., (effect of buoyancy neglected),
W = nominal pipe weight, lb. per ft.,
L = depth to freeze point, ft., or length of each section if there are more than one weight above freeze point.

If there are two or more weights of pipe above the estimated freeze point, each length can be used with the proper pipe weight to obtain a partial weight. The partial weights can then be added to obtain the total weight of pipe above the freeze point. The use of the chart of Fig. 2 will be explained more fully in the example that follows.

With earth movements eliminated from consideration, all of the variables except temperature rise and external pressure increase cause added tension so the necessity of keeping the initial landing weight to a minimum is obvious.

It can be said generally then that the landing weight should be the actual weight in air of the maximum amount of free pipe, plus an amount necessary to overcome the lengthening effect of anticipated temperature increases or external pressure increases that are likely to occur before the freeze point moves upward a substantial amount. If the freeze point is known to move upward rapidly the lengthening factors mentioned probably can be disregarded.

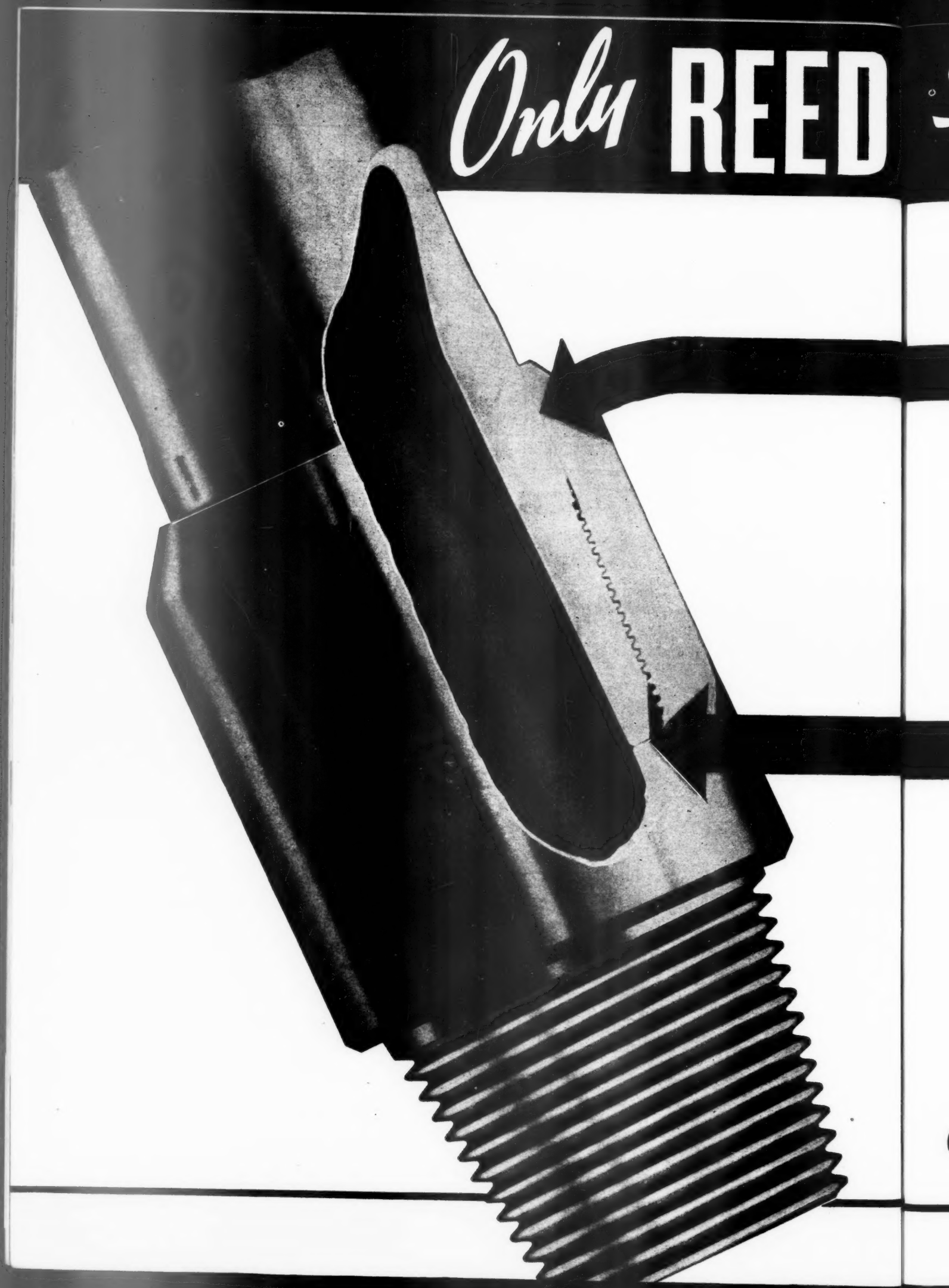
● **Example procedure.** A method of determining a satisfactory landing weight is shown in the charts of Figs. 1 and 2. Let us assume that the 10.000 ft. 7-in. casing program consisting of 8300 ft. of 7-in. 26-lb. N 80 with long couplings on top and 1700 ft. of 7-in. 29-lb. N-80 with long couplings on bottom previously referred to, is set in an area where the following conditions are encountered:

1. Calculated top of cement from displacement figures—6000 ft. from the surface.
2. Final freeze point—1000 ft. from the surface.
3. Average net pressure increase inside the free casing as compared to landing pressure—3000 lb. per sq. in.
4. Maximum average temperature rise of free casing after landing — 15°F.
5. Maximum average temperature drop of free casing after landing—18°F.
6. Diameter to thickness ratio, D/t of 7 in., 26-lb. casing = 19.34.

It will be assumed that the final freeze point and the temperature and pressure changes listed have been determined from other wells in the area. No attempt will be made in this discussion to go into the mathematics of temperature vs. depth prediction for flowing and static conditions.

The first determination to be made is the location as near as possible of the actual freeze point of the casing at the time it is landed. Some operators have used temperature surveys to locate the top of the cement and this method is probably satisfactory in most cases, especially when the result checks with displacement figures. However, if it is desired to make another check on the location of the freeze point, this can be done by the stretch method of Fig. 1. In the example to be worked out the nominal pipe weight above the calculated cement level is 26 lb. per ft. so a horizontal line is drawn from this value, (1) to intersect curve 1. A vertical line is then drawn to (2) which yields a weight to slack off to 38,000 lb. This means that the pipe that is hanging cemented in the derrick with the full weight of the string as indicated before cementing should be slacked off in the amount of 38,000 lb. after marking the casing approximately 2½ ft. above the rotary table. In this example it will be assumed that the mark lowered 10⅜ in. so a horizontal line is drawn from this value at (3) to intersect Curve 2. From this intersection a vertical line is drawn to (4), which indicates the depth to the freeze point is 5200 ft.

With the depth to freeze point established at approximately 5200 ft., the chart of Fig. 2 can be used to determine a proper landing weight. To obtain the weight of the free pipe, draw a horizontal line from 5200 ft. at (1) to the intersection of the pipe weight of 26 lb. per ft. From this intersection draw a vertical line to (2), which shows the weight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to be approximately 135,000 lb.

The effect of the average pressure change on the load at the landing head may be determined next. Since the diamter to thickness ratio of the free pipe is 19.34, a vertical line is drawn from this value at (3) to intersect the diagonal pressure line of 3000 lb. per sq. in., which is the average net pressure increase inside the free casing for this example. A horizontal line is then drawn to the diagonal pipe weight line of 26 lb. per ft., and a vertical line is then drawn from this intersection to (4), which yields an added load of 65,500 at the landing head. If this average net pressure increase had been outside rather than inside the casing, the effect at the landing head would be a reduced rather than an increased load.

To evaluate the effect of the 15° F. average temperature rise of the free pipe, a horizontal line is drawn from this value at (5) to intersect the diagonal 26-lb. line. From this intersection, a vertical line is drawn to (6), which shows approximately a 22,500 lb. weight reduction at the landing head for this temperature rise. The effect of the 18° F. average anticipated temperature drop can be found by drawing a horizontal line from 18° F. at (7) to a 26-lb. pipe weight. From this intersection a vertical line is drawn to (8), which shows an added weight of approximately 27,500 lb. at the landing head.

With the above figures in mind, a satisfactory landing weight may be determined as follows: The weight of the free pipe, at the time of landing, is 135,000 lb. Since the 22,500 lb. weight reduction at the landing head caused by the anticipated temperature rise of 15° F., is the only variable in this example that tends to cause slack in the casing, it will be necessary to increase the landing weight by 22,500 lb., making a total landing weight of 135,000 plus 22,500 or 157,500 lb.

If the pipe is landed with a weight of 157,500 lb. at the slips, and the added loads of 65,500 lb. caused by the 3000 lb. per sq. in. pressure rise and 27,500 lb. caused by the 18° F. temperature drop are later imposed, the total load at the head will then be 250,500 lb. This load is equivalent to a tensile stress of 33,200 lb. per sq. in. in the top joint of casing or a safety factor of 2.41 on the minimum yield strength of the pipe. The safety factor on the minimum pull-out strength of the casing couplings would be 1.84. Each of these safety factors is satisfactory although the 1.84 figure is lower than some operators wish to use.

If the pipe had been landed with its full buoyed weight of 225,000 lb. before cementing, however, and the loads of 65,500 lb. and 27,500 lb. were later brought to bear, the total weight at the landing head would then be 318,000 lb. This load would cause a tensile stress in the top joint of casing of 42,200 lb. per sq. in. or a safety factor of 1.90 on the minimum yield strength of the pipe. The safety factor on the minimum pull-out strength of the top coupling would be only 1.45 which is considerably lower than good practice would dictate. Inasmuch as the stress in the pipe itself is not beyond accepted maximums, this problem could be solved by the use of a stronger casing joint.

● **Conclusions.** It is believed that the example will illustrate the need of engineering consideration in the problem of landing casing. Were the depth and tensile loads greater, or the pressure and temperature changes more severe, dangerous stresses would have been induced that would cause casing failures.

Several operators have stated that they intend to install strain gages equipped with recording apparatus on the landing joint of casing so that data can be developed as to the actual variation of the load at the landing head. It is believed that an experiment of this type will bring to light reasons for some of the troubles that have occurred in casing after it has been landed. Reference to the data on biaxial loading in the API paper on "Setting Depth for Casing"[3] will show that large tensile loads have a substantial reducing effect on the resistance of casing to burst and collapse, especially when the tensile loads exceed 50 per cent of the yield strength. Taking this into consideration, the reasons set forth in this paper for keeping the landing weight to a minimum without placing any pipe in compression take on added significance.

APPENDIX

Derivation of equation (1):

The load necessary to produce a stress of 5000 lb. per sq. in. in a pipe of sectional area A is shown by the equation:

$$P = 5000\,A$$

The relationship between nominal weight and plain end area of casing is closely approximated by the equation:

$$A = \frac{W}{3.458}$$

$$\text{so } P = 5000\,\frac{W}{3.458}$$

$$(1)\quad P = 1445\,W$$

Derivation of equation (2):

The relationship of unit stress to unit strain for steel within the elastic limit is:

$$S = E\,e$$

and since it is desired to obtain the elongation for

$$S = 5000 \text{ lb. per sq. in.}$$

$$\text{and } e = \frac{\triangle L}{12\,L}$$

$$\text{so } 5000 = E\,\frac{\triangle L}{12\,L}$$

$$(2)\quad L = 500\,\triangle L$$

Derivation of equation (3):

The change in length due to temperature change for steel is:

$$e_t = 12\,L\,K\,\triangle T$$

and the change in length of steel under stress within the elastic limit is:

$$e_s = \frac{12\,PL}{AE}$$

equating e_t and e_s

$$12\,L\,K\triangle T = \frac{12\,PL}{AE}$$

$$P = K\triangle T\,A\,E$$

$$\text{since } A = \frac{W}{3.458}$$

and taking $K = 6.7 \times 10^{-6}$

$$(3)\quad P = 58.2\,W\triangle T$$

Derivation of equation (4):

Barlow's equation $s_h = \frac{pD}{2t}$

represents closely the average hoop stress in a pipe that is subjected to either internal or external pressure when the stress is within the elastic limit.

A change in the applied average pressure, $\triangle p$, produces a corresponding hoop stress change $\triangle s_h$

$$\triangle s_h = \frac{\triangle\,pD}{2t}$$

The longitudinal stress change, $\triangle s_1$, produced in a pipe that is anchored at both ends caused by an average hoop stress change of

$\triangle s_h$ is shown by the equation:

$$\triangle s_1 = M\,\triangle\,s_h$$

The effect at the landing head of $\triangle s_1$ is $P = A\,\triangle s_1$

$$\text{since } A = \frac{W}{3.458}$$

$$P = \frac{W}{3.458}\;M\;\frac{\triangle pD}{2t}$$

taking $M = 0.3$ for steel pipe

$$(4)\quad P = 0.0434\,W\triangle p\,\frac{D}{t}$$

If the average net pressure change $\triangle p$ is an internal increase, the effect at the landing head is an increased load. If the average net pressure change is an internal decrease (external increase), the effect at the landing head is a decreased load.

Nomenclature

P = change in load at landing head, lb.,

A = plain end area of casing, sq. in.,

W = nominal pipe weight, lb. per ft.,

s = unit stress, lb. per sq. in.,

E = Young's Modulus of Elasticity for Steel = 30×10^6,

e = unit strain, in. per in.,

$\triangle L$ = total elongation, in., or amount casing lowers,

L = depth to freeze point, ft.,

e_t = total change in length due to temperature change, in.,

e_s = total change in length due to stress, in.,

K = coeffcient of thermal expansion taken as 6.7×10^{-6} for steel pipe.

$\triangle T$ = average temperature change of free casing, ° F.,

s_h = average hoop stress, lb. per sq. in.,

p = pressure, lb. per sq. in.,

D = pipe O.D., in.,

t = pipe wall thickness. in.,

$\triangle s_h$ = hoop stress change caused by $\triangle p$, lb. per sq. in.,

$\triangle p$ = average net pressure change on free pipe, lb. per sq. in.,

$\triangle s_1$ = longitudinal stress caused by $\triangle s_h$, lb. per sq. in., and

M = Poisson's Ratio taken as 0.3 for steel pipe.

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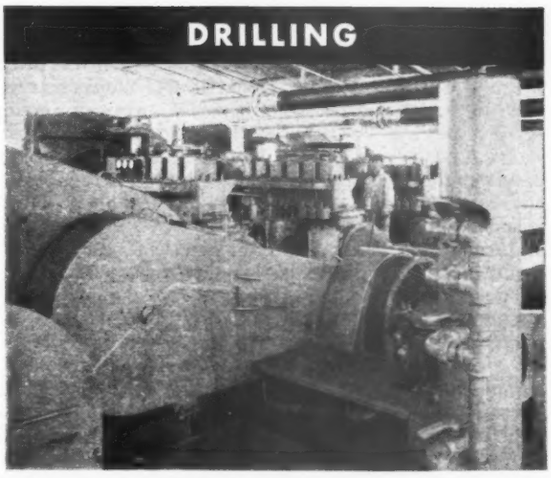

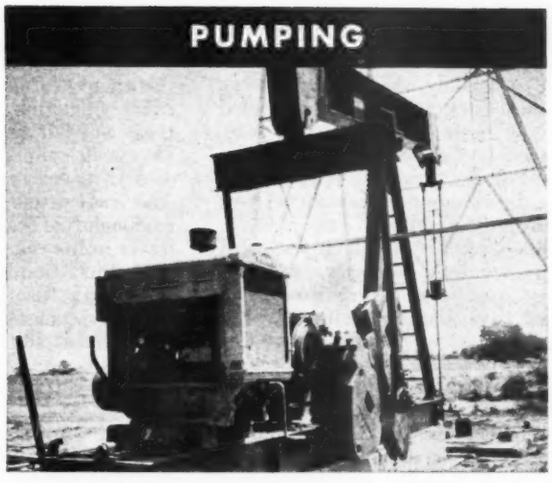

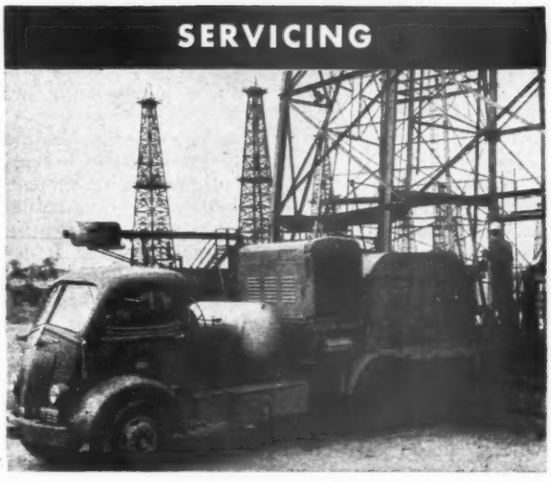

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140-GKU	6	4½x5½	525	111	1800
6-SRKRU	6	4⅝x5⅛	517	91	2000
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An Investigation of Oil Well Cementing*

A. J. TEPLITZ, Gulf Research and Development Company
W. E. HASSEBROEK, Halliburton Oil Well Cementing Company

IN the earlier days of oil well drilling, failures in cementing of production casing were relatively uncommon. For one thing, the casing was usually cemented in the top of the uppermost pay zone. Furthermore, the wells were usually shallow and the pressures available for causing fluid migration behind the casing were quite small.

As the search for petroleum extended to greater depths, however, and the practice of setting casing through a series of pays and producing through perforations became popular, the task of isolating the various formations became more difficult. In certain areas where comparatively unconsolidated sands occur accompanied by high formation pressures, the successful cementing of casing has constituted a most serious problem.

In these areas it is the general experience that after the casing has been cemented and perforated opposite the pay section, extraneous fluids such as gas or water are found to enter the well. Where this occurs, assuming the perforating interval has been properly selected, it is evident the cement seal behind the casing is imperfect. The usual procedure for repairing this seal consists of pumping cement through the perforations at high pressure and subsequently reperforating the casing—an operation commonly called "squeezing". Often one application of the process is successful in isolating the pay formation but not infrequently several such squeeze jobs are required to exclude the contaminating fluids. Sometimes the imperfections in the cement are not evident during the completion stage but appear later in the history of the well when the formation has been partially depleted and increased differential pressures produce movement of the fluids in the annulus. Although any recementing job adds considerably to the cost of a well, that required for treatment of the condition just described is extremely expensive because it usually necessitates the moving of a rig back on location.

Recently, faced with an increasing number of cementing failures, in a region where most of the drilling is conducted from barges over water, and operating costs therefore high, the authors' sponsors decided to make a thorough study of the physical processes occurring during the cementation of casing. It was hoped that the information gained would not only be of assistance in explaining certain phenomena observed during these operations, but also that it might possibly suggest some improvement in the art of setting casing.

In conducting this study, the various types of well logging services such as electrical, caliper, temperature, and radioactivity surveys were freely employed. The radioactive mineral, carnotite, a compound of uranium was used as a tracer in the cement, and during the experiments complete chronological logs were kept. Also, all pertinent data including volumes of fluids, pumping pressure, cement slurry densities, mud properties, etc., were recorded.

The investigation was confined largely to one particularly troublesome field in southern Louisiana, thus facilitating the correlation of the results of tests on the separate wells. A few tests were made, however, in West Texas, in an effort to determine the effects of one of the variables, i.e., hardness of formation, on the results.

To date, while the influences of a number of variables have not been ascertained, the investigation has tended to confirm the surmise that channeling or bypassing of mud by cement slurry is the chief obstacle to successful casing cementation. Furthermore, some insight into the nature and extent of this channeling has been gained, and one experiment with a variation in cementing procedure intended to alleviate this condition has been performed with promising results. Some valuable information on squeeze cementing was also obtained but much remains to be learned about this operation.

Some of the more significant results of these experiments are described for whatever interest they may contain for others concerned with these problems.

(1) In this well 5½-in. casing was set in 9⅞-in. hole to a depth of 9700 ft. with 500 sacks of slow setting cement containing ½ lb. of carnotite per sack. The casing setting was preceded by the usual electrical survey and by caliper and radioactivity surveys. After the setting, temperature log was obtained and another gamma ray survey was made. The casing was then perforated from 9560-9574 ft. and when the well was produced it was found to have an abnormally high gas-oil ratio for this particular sand. From the electrical survey it was suspected that a higher sand was the source of the excess gas and it was decided to squeeze the well in order to isolate the desired producing formation.

In the squeezing operation the formation was first broken down with mud at 2800 lb. per sq. in. surface pressure. Then 150 sacks of cement containing ¾ lb. of carnotite per sack were mixed and 120 sacks were forced through the perforations before the desired pressure of 4500 lb. per sq. in. was obtained. This corresponded to a bottom hole pressure of 9560 lb. per sq. in., the latter value being estimated with reasonable accuracy by summing up the pressure due to the hydrostatic heads of the known fluids in the hole and the surface pressure indicated on a recording chart attached to the cementing truck. At the time the final pressure was reached the rate of injection of fluid into the well was practically zero so that it was unnecessary to correct the surface pressure reading for frictional loss in the pipe. It should also be mentioned that it was necessary to considerably reduce the rate of pumping the cement in order to obtain the desired final pressure.

After the squeezing operation another gamma ray survey was made, after which the casing was reperforated in the original interval and the well was brought in with normal gas-oil ratio.

Fig. 1 shows some of the logs made during the test. A section of the surveys in that part of the hole which is of minor interest has been removed to conserve space. Also for condensation, the original gamma ray log has been omitted, and the differentials between it and the radioactivity logs obtained after casing cementation and the squeeze job are presented reduced to one-tenth horizontal scale.

The area between the base line and the first differential curve is representative of the original casing cement, while the cross-hatched section between the two differential curves is indicative of the position of squeeze cement. It should be pointed out that the relationship between these differentials is not linear. For one thing, different proportions of carnotite were employed in the various stages of cementing. Furthermore, the amplitude of the gamma-ray curve is a somewhat complicated function of the quantity of radioactive matter, involving its strength and distance from the detector as well as the absorptive capacity of any intervening material. The data shown, therefore, represent only a qualitative picture of the distribution of the cement.

According to the caliper survey, the quantity of cement used should have filled the casing annulus to approximately 8400 ft. Actually, as is indicated by both the temperature and gamma-ray curves, the main top of the cement was found at about 6600 ft., i.e., 1800 ft. above the theoretical fill up.

It is of particular interest to note that the squeeze cement progressed up the hole to almost the same extent as the original cement used to set the casing, and it is evident that the squeeze job was principally a recementing job. The performance during squeezing, however, did not appear to vary from that of other similar operations in the same area. Hence, it seems likely that this same behavior has occurred in other instances where it has been assumed that the squeeze cement has been confined to a rather small zone.

*Presented before Southwestern District API Division of Production, Shreveport, Louisiana, May 17-18, 1946.

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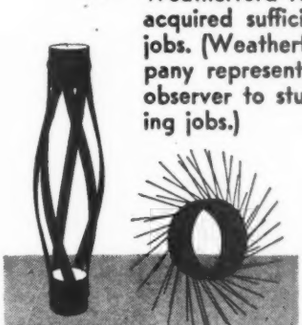

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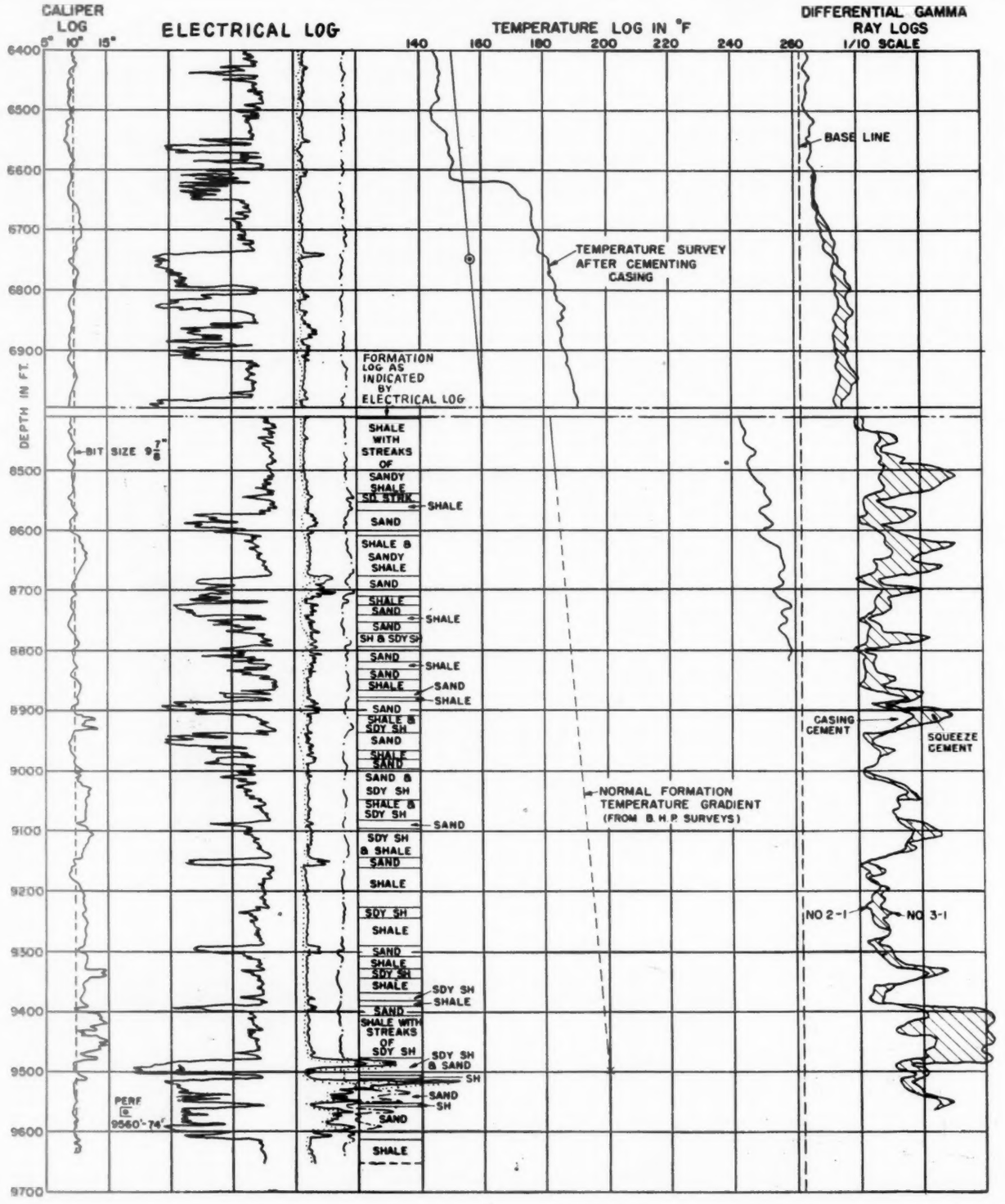
Since the annulus surrounding the 5½-in. casing was kept full and no efflux of mud or water appeared at the surface during the squeezing, the question arises as to the disposition of the fluid displaced by the cement. Comparison of the first differential gamma-ray survey with the caliper log indicates that considerable portions of the enlarged sections of the hole were filled with the original casing cement. The differential curve shows that most of the squeeze cement was deposited in those same enlarged portions, and it is probable that the mud displaced was forced out into the formations in the upper part of the hole.

(2). In contrast to the preceding example was another well in the same field in which comparatively large volumes of cement were squeezed in two operations into a much smaller section of hole. The size of the hole and the casing and the manner of completion were similar to those described in the previous case except that the gamma-ray survey before the casing cementation was omitted. Furthermore, in setting the casing with 750 sacks, the carnotite was added at regularly spaced intervals by the method described by Scherbatskov,[2] for the purpose of obtaining more detailed information on the distribution of the casing cement. In this particular instance, probably because the batches were so small, the radioactive cement did not remain segregated but mixed rather uniformly with the untreated cement so that the purpose of the procedure was not achieved.

After perforating the casing between 9456 and 9466 ft., the production test was made and the well produced 60 to 98 per

FIG. 1.



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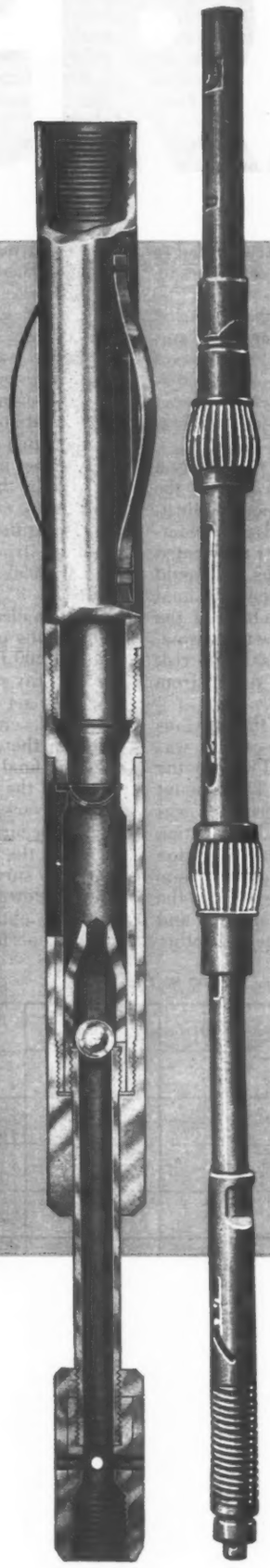

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cent salt water. In attempting to isolate the producing zone, the perforations were squeezed with 578 sacks of cement containing ¼ lb. of carnotite per sack. The break-down pressure with mud was 2500 lb. per sq. in., and the final pressure was 3900 lb. per sq. in. at the surface or 8960 lb. per sq. in. bottom hole. This pressure was reached only by slowing down the rate of pumping. After allowing the cement to set and making a radioactivity survey, the casing was again perforated for production in the original interval. This time the well made about 50 per cent water. Analysis of this water indicated that its source might be different from that obtained in the first production test, but because of the similarity of composition of waters from all sands in the vicinity of the producing zone, this point could not be definitely established.

In the further attempt to shut off the water, these perforations were again squeezed with 265 sacks of cement containing ½ lb. of carnotite per sack with a breakdown of 3600 lb. per sq. in. and a final surface pressure of 4700 lb. per sq. in. (10,080 lb. per sq. in. bottom hole). In this case, the final pressure was attained without any appreciable reduction of the pumping rate. After a radioactivity survey had been made the casing was then reperforated in the same zone, 9456 9466 ft., and this time the well produced pipe line oil.

Portions of some of the records obtained during these operations are reproduced in Fig. 2. It may be seen from the radioactivity logs that the squeeze cement did not travel higher than 9100 ft. Above this level the gamma-ray log taken after the squeeze job is quite similar in appearance to the radioactive survey of the casing cement. Below this depth however, Log 2 exhibits a decided change in configuration, the deflections being longer and the individual characteristics being thicker, both of which are indicative of increased gamma-ray activity. Log 3 indicates that the cement in the second squeezing operation contributed very little additional radioactivity from 9100 to 9440 ft., but did so below this region, the increase being due to the greater concentration of carnotite as well as the extra material placed there. The cross-hatched portions of the curves are deflections which extended beyond the scale of the instrument chart and had to be set back so that they could be recorded on the paper.

A better comparison of the more important portions of the radioactivity surveys is afforded by the combined curves shown in Fig. 3, where it is evident that the greater part of the squeeze cement was forced downward from the perforations at 9456-9466 ft.

The 845 sacks squeezed represents a volume considerably in excess of the hole available for displacement, indicating that in addition to mud a considerable quantity of cement either penetrated or displaced the formations. It would have been interesting to extend the final gamma-ray survey to the bottom of the hole, which was 120 ft. below the casing, but it was not deemed advisable to risk the damage which might result from drilling out the casing shoe.

In this last example as in the previous case, the top of the casing cement was found considerably above (1300 ft.) the point of theoretical fill-up. The amount of channeling in these experiments was so much greater than had been anticipated that the causes for this condition was the subject of much speculation. One very obvious difference between the wells in the area under examination and those in other localities where cementing failures were relatively infrequent was the occurrence in the former wells of a comparatively large number of rather loose sands with intervening sections of shale which were badly washed out and enlarged considerably over bit size.

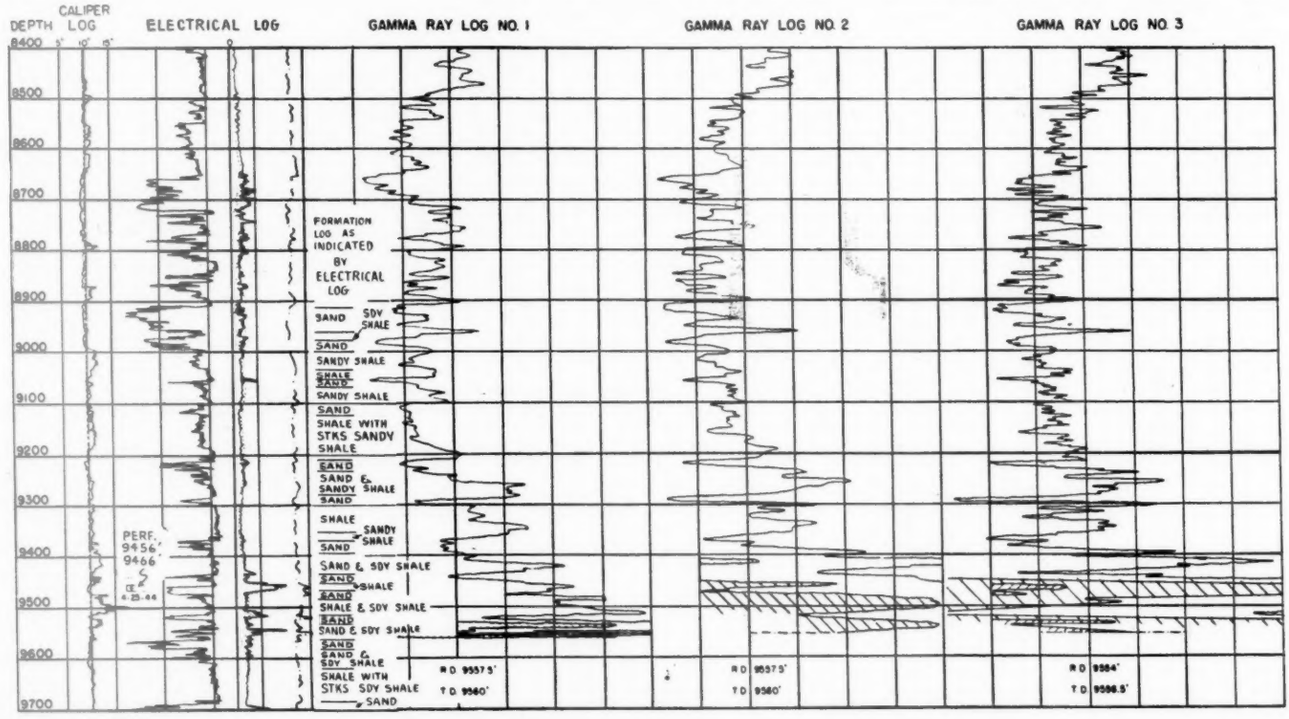
Some experiments were made, therefore, in much the same fashion as those already described in wells drilled in the hard limestone formations of West Texas where the holes were found to conform more closely to bit size. These tests were somewhat complicated by the fact that considerable quantities of cement slurry were lost into the very permeable limestone formations, nevertheless the indications were that, in general, channeling was much less severe than in the previous experiments.

While awaiting the opportunity to further investigate the effect of regularity of hole diameter on channeling a well presented itself in the original field of study which offered possibilities of yielding further information on the subject.

(3). In this well the producing zone had been expected to be encountered at greater depth than usual and an intermediate string of 9⅝-in. casing had been set at 8050 ft. Drilling was continued with an 8½-in. bit to 9500 ft., after which an electrical survey was made disclosing the presence of the oil sand just under 9500 ft. After making caliper and gamma-ray surveys the usual 5½-in. casing was set through the pay with 460 sacks of cement. Carnotite was distributed in the cement in batches, the first 75 and final 260 sacks each containing ⅛ lb. of the mineral, while the intervening 125 sacks was left inert.

The occurrence of a storm prevented entering the well in time to make a temperature survey, but when the water had calmed down sufficiently, a radioactivity log was obtained and the well subsequently perforated for production. The

FIG. 2.



casing seal was evidently faulty since a considerable quantity of water was produced with the oil and the well was squeezed with 355 sacks of cement containing ⅛ lb. of carnotite per sack at a maximum and final pressure of 4700 lb. per sq. in. corresponding to a bottom hole pressure of 11,035 lb. per sq. in. This treatment was successful for the well made pipe line oil when the casing was again perforated in the original interval.

The various logs obtained during this work are reproduced in Fig. 4. The three gamma-ray surveys made before running casing, after cementing casing, and after squeezing, are superimposed so that the disposition of the cement in the two jobs are readily distinguishable.

According to the caliper survey,* the 460 sacks of cement used in setting the casing should have filled the lower annulus and extended between the two casing strings to a height of 7900 ft., assuming a 16-lb. slurry had been maintained. Actually the average slurry density was only 15 lb. per gal., changing the figure for the fill-up to approximately 7680 ft. However, as the radioactivity survey shows, the casing cement rose about 900 ft. higher to 6800 ft., indicating considerable channeling. The relative extent of channeling in the cased hole and between the casing strings can be distinguished because of a rather fortunate choice in the sizes of the carnotite batches.

From the second gamma-ray curve it is evident that considerable mixing took place between the latter portion of the first 75 sacks of cement containing carnotite and the next 125 sacks which was free from radioactive material. Some mixing also occurred within the next 260 sack batch of carnotite cement slurry but not to such an extent as to entirely obscure the upper boundary of this batch. This top is probably at 7830 ft. and certainly not below 7960 ft. This conclusion is arrived at by a careful comparison of the amplitude of the radioactive curve at various points above and below the 9⅝-in. casing seat, taking into consideration the shaliness of the formations as indicated by the electrical and original gamma-ray surveys, the variations of the hole diameter from bit size, and the gamma-ray absorption effects of the casing strings. In making the examination of the gamma-ray curve, attention was directed to the values of the shales rather than those of the sands, since the latter have nearly zero radioactivity and therefore, are less sensitive to shielding effects of the casings.

From such an analysis, it appears that a point about midway between the depths mentioned, say 7900 ft., may be selected for the upper limit of the final 260 sack batch of casing cement, without introducing any error which would seriously effect the comparisons that are to be made. On this basis, then, it may be stated that the first 200 sacks (75 of radioactive plus 125 of inert) of cement occupied the space between the two casing strings from 6800 ft. to 7900 ft. According to volumetric calculations, however, 200 sacks of cement made into a 15-lb. slurry should fill this annulus for a length of only 975 ft., meaning that about 225 ft. of mud was trapped in the column. If, for the purpose of this discussion only, the degree of channeling is defined as the proportion of bypassed mud to the gross space pervaded by cement, the condition between the casing strings would correspond to a channeling of about 11 per cent.

This figure seems rather high assuming that the slurry had merely to displace the mud between the presumably smooth steel surfaces of the 5½-in and 9⅝-in. casings, but the possibility cannot be overlooked that some contamination occurred at greater depth and was carried up between the two casings. At any rate the channeling or contamination is not so great when compared with that which took place between the 5½-in. casing and the formation walls. In this case, making due allowance for the small portion of the last cement batch which rose above 8050 ft., approximately 252 sacks of cement were disposed in the annulus between the 5½-in. casing and the drilled hole from the 9⅝-in. casing seat to bottom. According to the caliper log, however, this space should have returned 380 sacks of cement (with a slurry density of 15 lb. per gal.), indicating that a volume of mud equivalent to 148 sacks of cement, mixed into a 15-lb. slurry, was trapped. By the definition previously stated this corresponds to 39 per cent channeling, which is considerably in excess of that which occurred between the casing strings.

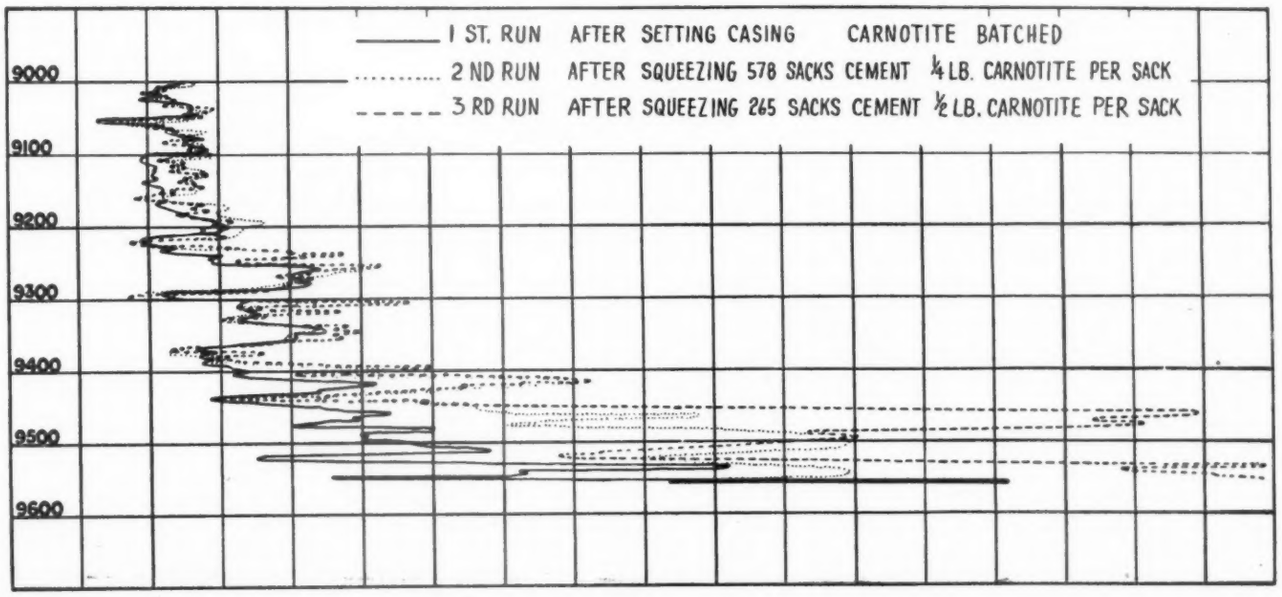
Looking further into the nature of this channeling it will be noted that in the two tests previously cited, it was discovered that the casing cement did not fill the enlarged portions of the hole, for after successive squeeze jobs increasing amounts of cement were deposited in these cavities as indicated by the radioactivity data. The present well, no doubt, behaved similarly, however it may be readily ascertained that not all the channeling was due to the by-passing of these enlargements. Even if the hole below the intermediate casing had been true to bit size (8½ in.), to fill this lower annulus a quantity of 15 lb. slurry equivalent to 300 sacks of cement would have been required. The finding that only 232 sacks were present indicates some trapping of mud beyond that which occurred in the cavities themselves.

Comparing the results of the three experiments described it is found that degrees of channeling amount to 53 per cent, 40 per cent, and 39 per cent, respectively, considering only the annulus

*Results of gravel packing experiments indicate that volumes as calculated from caliper surveys agree within 10 per cent of the actual volume of the hole.

FIG. 3.

COMPOSITE OF GAMMA RAYS SURVEYS


1 ST. RUN AFTER SETTING CASING CARNOTITE BATCHED
2 ND RUN AFTER SQUEEZING 578 SACKS CEMENT ¼ LB. CARNOTITE PER SACK
3 RD RUN AFTER SQUEEZING 265 SACKS CEMENT ½ LB. CARNOTITE PER SACK
9000
9100
9200
9300
9400
9500
9600

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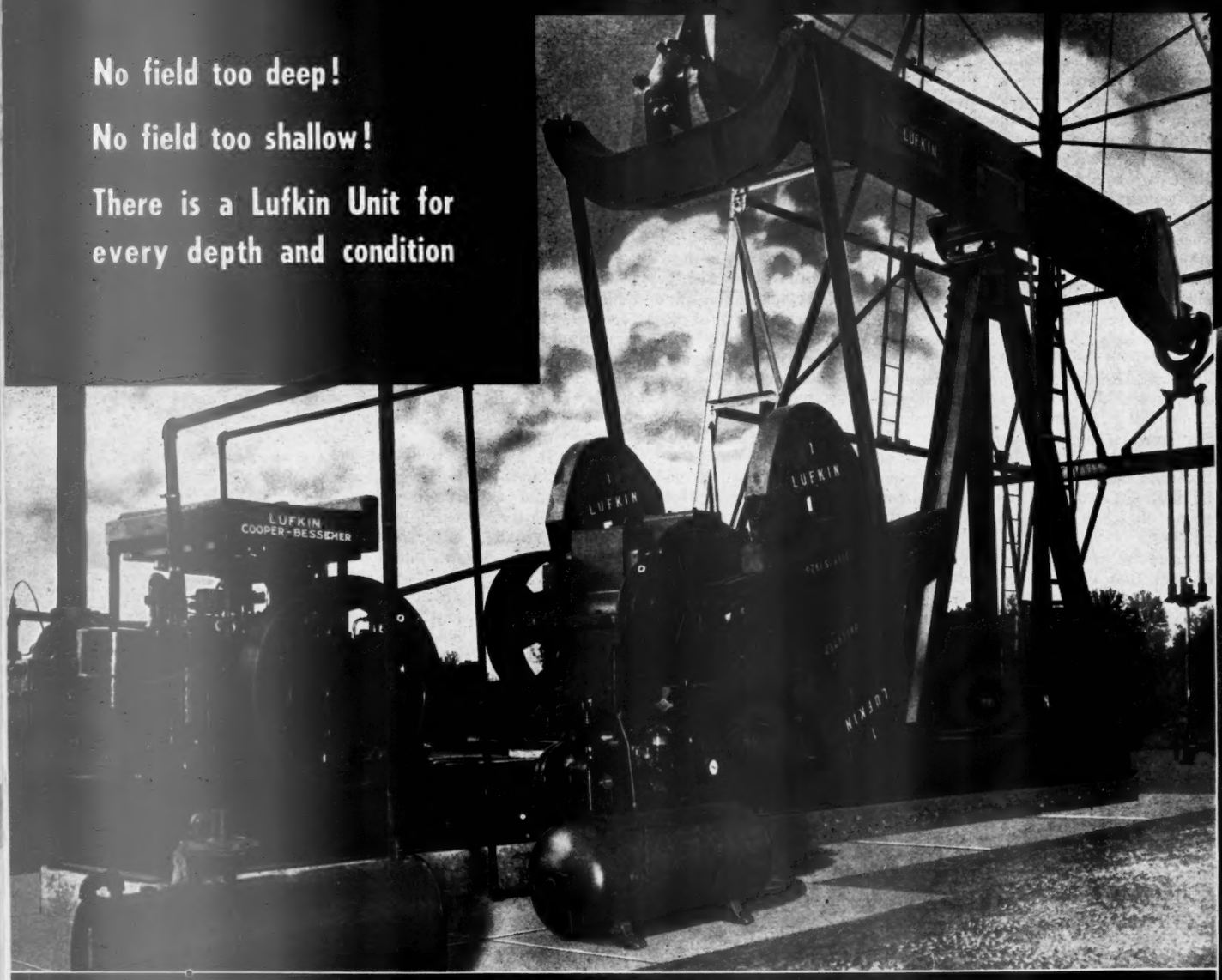

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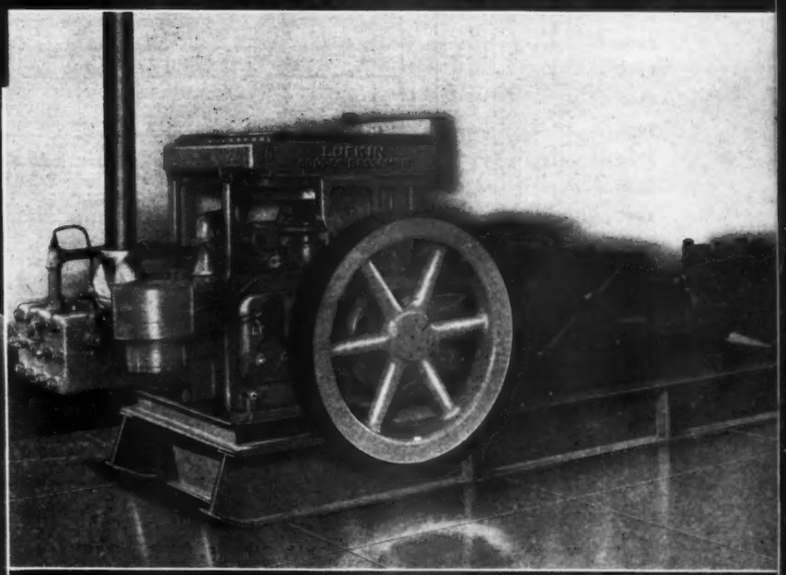

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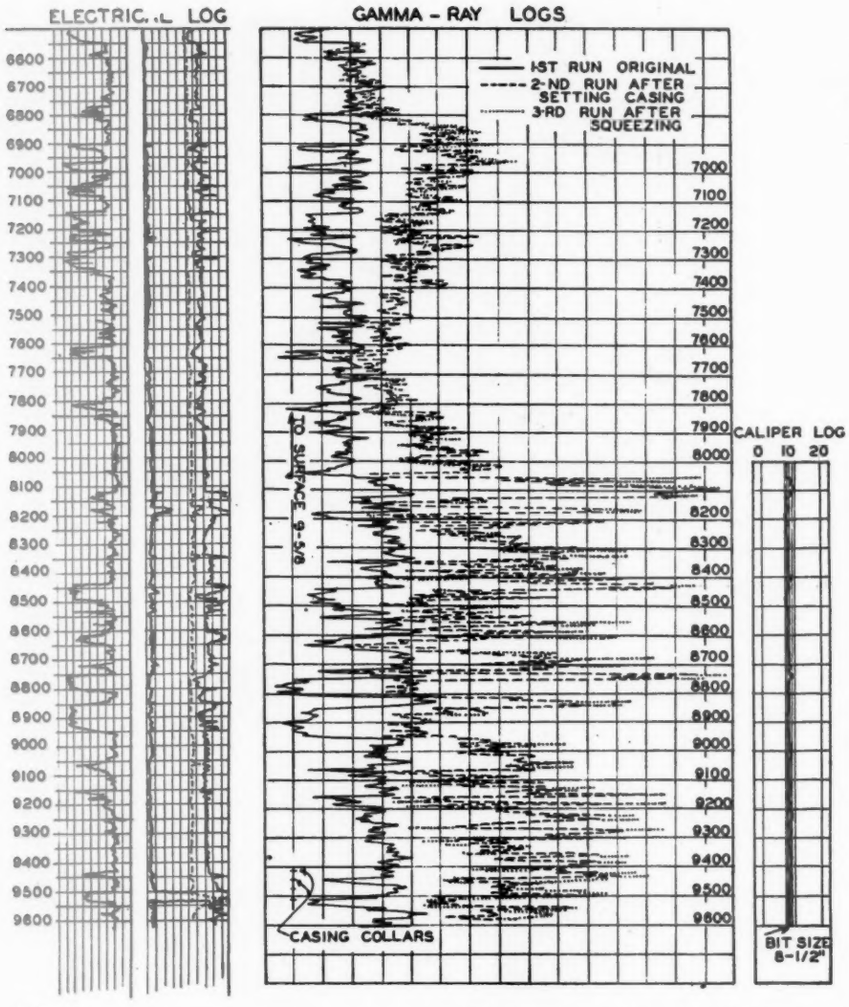


FIG. 4.

between casing and open hole. Stated simply this means that in the field under discussion, the usual casing cementation ends up with the annular column consisting roughly of half cement and half mud, i.e, over the total distance pervaded by cement.

An interesting sidelight on this information is that it tends to support the work of Farris[3], who advocates reduction of waiting-on-cement time, on the grounds that the strength requirements of casing cement are much less than is generally supposed. It is quite evident that in the examples cited in this paper, the strength of the casing cement must have been only a fraction of that which had been considered necessary for the job. Yet in spite of the high formation pressures existing in the field, failures due to collapse or movement of casing have not occurred. Instead, the troubles have been caused by channeling which is certainly not a function of the strength of the cement.

This information suggests further, since high strength is not required, the reduction in slurry densities in areas such as West Texas where cement is lost into permeable formations due to high hydrostatic head of the cement column during casing setting.

To return to the original course of this discussion, at this point in the investigation it was thought that a sufficient background of information had been obtained on cementing casing in the usual manner, and that it was now time to determine the effects of variations in the procedure. Among the deviations from normal practice under consideration were, reduction in the hole size, increased rate of pumping of cement, alterations in physical and chemical properties of the cement slurry, movement of the casing during cementing, and the use of scratchers and centralizers on the casing.

The first venture on this new program took place very recently, as a matter of fact less than a month ago, so that time was not available to prepare graphical illustrations of the data for this paper. The test consisted of applying scratchers and guides to the casing, reciprocating the pipe during the cementing operation, and speeding up the rate of pumping the cementing plugs. The results of this experiment were very interesting and gratifying and deserve description here.

(4). This well found an oil sand at 8200 ft. but the 9⅞-in. hole was drilled to 9700 ft. for exploratory purposes. No deeper sands of any value were discovered. It was decided to run the 5½-in. casing to 8430 ft. in order to tie into and seal off a water sand at that depth, since there was to be no bridge in the open hole below. The bottom 750 ft of casing was equipped with eight spiral guides and 44 scratchers, spaced at strategic intervals. The guides were intended to keep the pipe away from the sides of the hole, bridge across keyseats, and also to protect the scratchers, the purpose of which was to remove mud cake from the sands and cuttings from the cavities. The scratchers, provided with 5-in. bristles, were of a type designed to reverse in small hole and to open up to an overall diameter of 15 in. in the enlarged portion of the hole.

The pipe was continuously moved up and down over a distance of 35 ft. from the time it was landed until the cementing plugs were pumped against the float collar, a period of slightly more than an hour. The running of the casing and its movements was accomplished with great ease. In pumping down the plugs, the two 20-in. pumps were compounded and connected to the cementing head by two 4-in. hoses, and the operation required only 12 min. instead of the customary 18 to 25 min. The 474 sacks of cement used in setting the casing contained carnotite as a tracer.

The subsequent temperature and gamma-ray surveys revealed the top of the cement at a position about 180 ft. below the point of theoretical fill-up as indicated by the caliper log. This was remarkable in view of the fact that in all previous tests the cement top had exceeded the theoretical fill-up from 1000 ft. to 2000 ft. That the fill-up was less than the amount calculated must have been due to the material removed from the walls of the hole, since large quantities of thickened mud and formation cuttings were observed to flow over the shale shaker while the plugs were being pumped down.

The results indicated also that channeling had been greatly reduced and probably eliminated. It was understandable, therefore, that when the well was brought in it made pipe line oil. This behavior was unusual, nevertheless, since about 75 per cent of the wells previously drilled in this particular field had required squeezing at the time of completion.

In the past two weeks three other strings of casing were set with spiral guides and scratchers in a similar manner in wells in the same area. In each case the cement top was found to be from 100 to 200 ft. below the theoretical fill up as calculated from caliper surveys. All the wells produced pipe line oil on completion without squeezing.

Two of these wells presented rather severe conditions for the tests. In one well the casing had to be set in a sidetracked hole after bare casing had been stuck and cut out of the original well. In the other instance the producing perforations were less than 10 ft. above a water sand.

It should be pointed out, however, that even if it becomes possible to entirely eliminate cementing failures at the time of setting casing, some type of squeezing

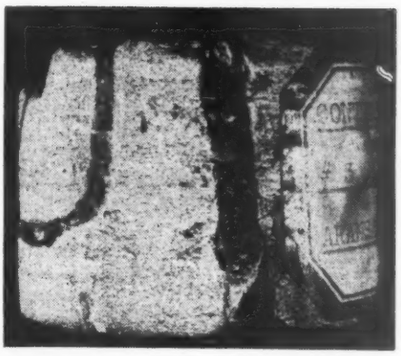


FIG. 5.

operation will probably be required to take care of conditions such as, abandonment of old pay zones, perforations improperly placed, encroachment of water, casing leaks, and so forth. For these reasons it was intended that part of this research on cementing should be devoted to the squeezing process.

Thus far in the program a detailed study of squeeze cementing has not been made but certain points have presented themselves which are perhaps worthy of mention.

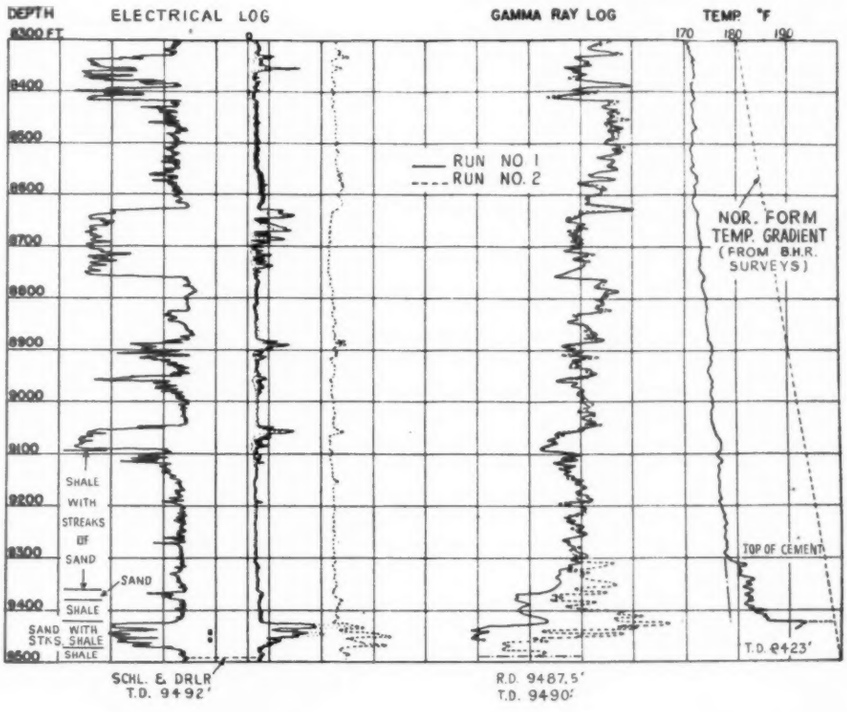
It is customary in squeezing operations to select some final pressure to be attained before the job is considered completed. The choice of this pressure varies with the locality and the depth of the well. The selected pressure is a surface value and does not take into consideration the actual pressure existing at the formation at the bottom of the hole. In squeeze jobs observed in the course of this study, the chronological records maintained provided a knowledge of the density of the fluid column in the well at all times. When conditions approached static, that is, when the rate of fluid injection was low, the bottom hold pressure could be estimated readily. But when appreciable volumes of cement were being squeezed the situation was more complicated since frictional losses were difficult to evaluate. However, calculations based on rough estimates of the frictional effect indicated that the squeezing operation frequently ended with a lower bottom hole pressure than had existed at some earlier stage of the job, even though the chart at the surface recorded increasing pressures throughout the process. It would seem, therefore, that some criterion other than surface pressure ought to be employed in determining the time when cement injection should be discontinued.

According to the usual concept of squeezing, the pressures exerted lift the overlying sediments permitting the cement slurry to flow into the parting between the formations in a more or less pancake shape, forming a barrier to further vertical movement of fluids in the annulus surrounding the casing. It would seem advisable therefore to stop the injection of cement shortly after the pressure against the formation has exceeded that of the overburden and a reasonable quantity of cement has been forced out. Experiments to test out this thought are now being planned.

It is difficult to imagine that any benefit may be derived by forcing the cement beyond a few feet from the bore of the well. On the other hand it appears possible that prolonged injection of cement at high pressure might extend the parted fractured zone to such a degree as to be detrimental to the well. The sand core[4] pictured in Fig. 5, is believed to demonstrate the results of such action. This core was obtained from the producing horizon in a side tracked well after the original hole had been subjected to a number of squeeze jobs. According to the best estimates the lateral displacement of this core from the squeezed zone in the original well was approximately 21 feet. It will be noted that the most prominent cement vein runs perpendicular to the plane of bedding in the sand, (part of the vein has been cut out for chemical analysis). Several feet of such core containing cement streaks were recovered, and it is inconceivable that cement dykes of this nature traversing an oil sand can fail to reduce the productivity of wells in their vicinity.

In addition to showing that cement squeezing may be harmful to a producing sand, this specimen also provides other information concerning the physical processes involved in such operations. A microscopical examination of the core reveals the presence of a thin filter cake, containing barytes, between the cement and the face of the sand, but no traces of cement or mud particles was visible within the sand itself. This is in agreement with the results of laboratory experiments indicating that cement slurries cannot be injected into any but the coarsest of sands even at pressures greatly exceeding those involved in cement squeezing.

FIG. 6.



It is not difficult to visualize the mechanism of pressure parting, as described by Yuster and Calhoun[5], when water is the injected medium. In this case pressure applied at the well bore is readily transmitted through the water which has entered permeable strata and the forces may be applied to the overburden over a considerable area. However, with mud or cement which cannot penetrate the ordinary sand or shale formations the physical picture is rather obscure. Unless these fluids can gain entrance through a relatively large crevice or obtain a purchase on some hard ledge, the forces necessary to lift the overlying sediments cannot be exerted. It is possible that the badly washed out shale sections in some wells leaving the comparatively hard sands projecting provide the required conditions for formation lifting. However, there is some evidence that the necessary lever is produced during the squeezing operation itself by the compaction and lateral movement of the shales away from the bore of the well. The following record of the squeezing of a well in Southern Louisiana serves to illustrate this point.

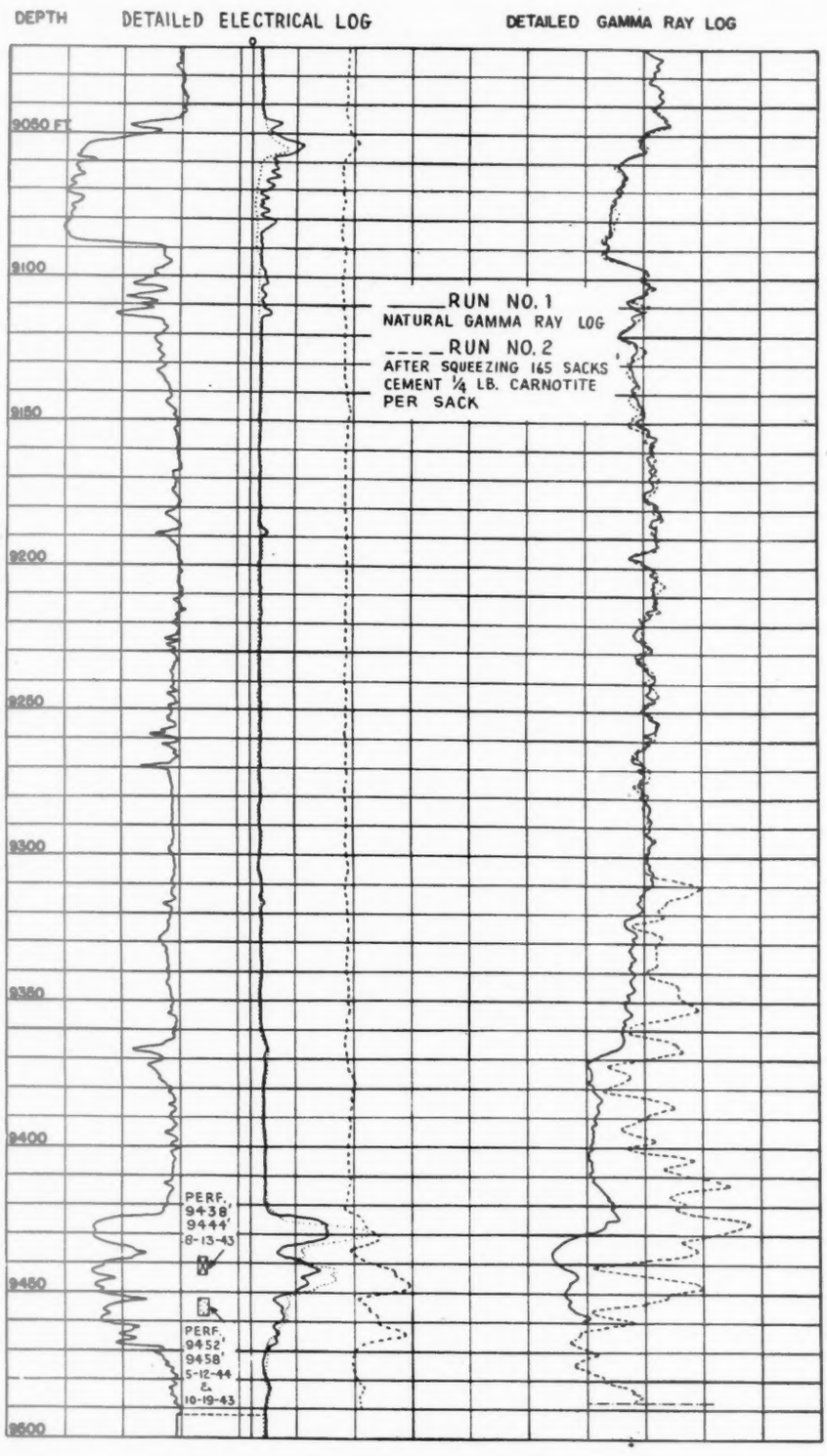
This well had been drilled about a year previous to the time of the remedial work which is to be described. Shortly after completion, it had developed a high gas-oil ratio and the perforations had been squeezed with 485 sacks of non-radioactive cement. The casing had then been perforated in a section about ten feet below the bottom of the previous openings, after which the well produced with a normal ratio. During the next five months, however, the gas-oil ratio had gradually risen to its original excessive value, and at the end of that period, the present radioactive squeeze operations was performed.

At the commencement of this job, the well which had been killed was surveyed

with the gamma-ray detector. The producing perforations, 9452-9458 ft. were then squeezed with 165 sacks of cement containing ¼ lb. of carnotite per sack. The break-down pressure was 3600 lb. per sq. in. with mud, and the final pressure was 5000 lb. per sq. in. at the surface, or 11,214 lb. per sq. in. at the bottom of the hole. Immediately following the squeezing, a temperature survey was made. After the cement had been allowed to set it was drilled to within 3 ft. of the lower end of the casing which had been set at the bottom of the hole. The casing was then reperforated in the same interval 9452 to 9458 ft. and the subsequent production test revealed that the gas-oil ratio had been lowered to the normal value.

Fig. 6 contains part of the original electrical log of the hole as well as the records obtained during the workover. The radio activity logs made before and after squeezing are shown in solid and broken lines respectively. The temperature curve obtained after the squeeze job is shown alongside the broken line, which corresponds to the normal temperature gradient, as recorded in bottom-hole pressure surveys made in the field. The detailed electrical and gamma-ray logs of the bottom 500 ft. are reproduced in Fig. 7.

FIG. 7.



Several interesting points are observed in a study of these records. First, it will be noted in Fig. 6 that there is a remarkable resemblance between the lower parts of the temperature log and the second gamma-ray log. Exceptionally good agreement is found in the top of the squeeze cement as indicated by both instruments, and in addition there is good correspondence between the individual peaks and valleys representing variations in the quantity of squeeze cement.

As the surveys indicate, practically all the squeeze cement was deposited from 9506 ft. to the bottom of the hole. Because the ionization chamber is relatively insensitive to that portion of the radioactive matter which extends beyond a foot or so from the hole, it would be difficult in general to make more than a rough estimation of the manner of disposition of the squeeze cement.

The comparatively high radioactivity in the interval from 9400-9450 ft. could possibly be ambiguous. It could be due either to a larger concentration of the carnotite-cement mixture in this region. or the placement of the cement in closer proximity to the casing. For example, the greatest portion of the 165 sacks of cement could have moved outward from the well into some bedding plane, say around 9350 ft., to such a distance that its effect on the ionization chamber would be considerably less than that of a much smaller quantity of cement deposited immediately adjacent to the casing.

This argument is put forth for the purpose of pointing out some of the difficulties that might be encountered in interpreting such a radioactivity survey in general. In the present case, fortunately, some additional information is discernible which gives special significance to the data.

In Fig. 7, it will be noted that the preliminary gamma-ray log exhibits a shifting toward the left, beginning at 9310 ft. and extending downward. Deflections toward the left denote diminishing radioactivity and since there is no reason to expect any such sudden change in the character of the sediments. (no shifts of this nature were exhibited in natural radioactivity logs obtained in adjoining wells) it may reasonably be inferred that the ionization chamber in traversing this zone was being shielded to some extent from the natural radioactivity of the formations. Since it is known that the well previously had been squeezed in virtually the same interval with non-radioactive cement, the most obvious explanation for the observed behavior is that a considerable portion of this cement was lodged behind the casing over this interval, thus forming a screen which would absorb some of the

gamma-rays emanating from the formations toward the well.

Some reduction of radioactivity in the zone in question was to be expected because of presence of a sand body that normally is lower in radioactive content than the shales. Also, the original casing cement would account for some absorption. But as the electrical survey shows, the lower sand formations are more shaly than those extending from 9050-9095 ft., and therefore, except for the presence of the non-radioactive squeeze cement, the position of the gamma-ray curve in the lower zone should be somewhat to the right of the curve opposite the upper sand. Other radioactivity surveys of the same horizon in adjoining wells substantiate this interpretation. The effect of the original casing cement naturally cancels out the picture, since it is present over the whole length of the surveys.

Again looking at the radioactivity logs in Fig. 7, it will be noted that the gamma-ray curve obtained after squeezing with the carnotite cement mixture begins to move toward the right, that is, toward higher radioactivity, at about the same point that the preliminary curve shifts to the left. As the curves progress downward a more or less mirror image is observed, indicating that the cement in the two squeeze jobs oriented itself in much the same fashion. Furthermore, this suggests that a considerable portion of the cement in both cases was deposited within the immediate vicinity of the borehole, and this is borne out to some extent by the temperature survey in Fig. 6. If practically all of the cement had been forced out between the formations for any great distance, it is doubtful that such a large deflection in the temperature curve would have been obtained.

The foregoing observations suggest the somewhat radical view that some lateral movement of the walls of the hole occurred during the squeezing operations. Since movement of the sands would require crushing of the individual grains and the forces available were not sufficient for such a mechanism, it appears that compression or displacement of the shales might have been effected to some extent. The shales are more or less plastic and have been known to flow into drilling wells in a number of instances under lower differential pressures than were available in this particular well. During the squeezing operation, it was estimated that the pressure at the perforations exceeded the overburden pressure by approximately 2000 lb. per sq. in., and it is conceivable that such forces might effect the movement of the relatively unlithified shales found in Gulf Coast wells.

Another possible means by which the walls of the hole may be displaced is the direct compression of the shales. Although no compressibility measurements of deeply buried shale bodies are quoted in the literature, approximate values have been estimated from elasticity data[1] on sedimentary materials. These values suggest that at the pressures involved in ordinary squeezing operations considerable compaction of shale may occur. As a matter of fact, these calculations indicate that with the 2000 lb. per sq in., differential pressure available in the two squeeze jobs on the last well cited, the entire 650 sacks of cement put away could have been accommodated in the space voided by the compressibility of the shales in the interval 9306-9492 ft. over an average distance of 32 ft. from the bore of the well. Furthermore the distance over which compaction must take place would be materially reduced if part of the water from the shales was squeezed out into the adjoining porous sand formations.

It appears reasonable that in the squeeze jobs studied a combination of these phenomena occurred. Thus after the shales had been moved back and compacted, the ledges of harder sediments exposed could have afforded the surfaces upon which the injected fluids could act to part the formations.

● **Conclusions.** 1. The results of this study indicate that considerable value may be derived from a methodical effort to obtain information on the physical processes occurring during cementing operations with the aid of electrical, caliper, radioactivity and temperature surveys and with any other logging instruments which may be available.

2. The experiments performed in the course of this investigation have shown that extensive channeling of cement occurs in the ordinary procedure of casing cementation, and indicate that this condition is responsible for most of the failures encountered.

3. By properly equipping the casing with scratchers and centralizing devices, reciprocating the pipe while placing the cement, and speeding up the rate of pumping, it has been possible to practically eliminate channeling and thus greatly increase the proportion of successful casing settings.

4. The physical changes occurring underground during the squeezing process are as yet little understood. It appears that in some cases this operation may be harmful to producing formations, but it is believed that further study of this type of cementing will aid in reducing the hazards involved.

Acknowledgments.

The authors wish to express their appreciation to Drs. P. D. Foote and B. B. Wescott of the Gulf Research & Development Company and to W. D. Owsley of the Halliburton Oil Well Cementing Company for permission to publish this material; to E. P. Hubbard of the Gulf Oil Corporation who directed much of the experimental work; and to various members of the same organizations who contributed valuable suggestions.

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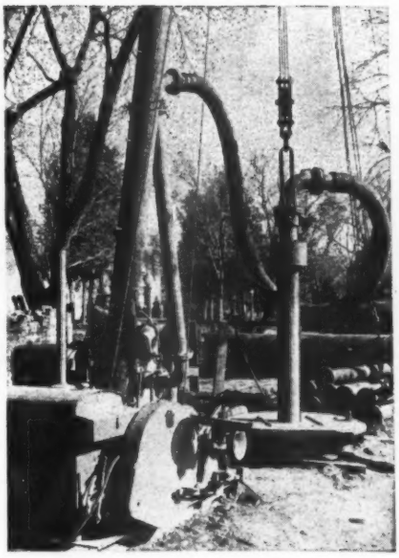

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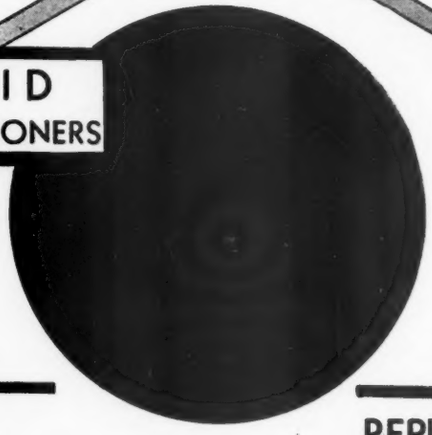

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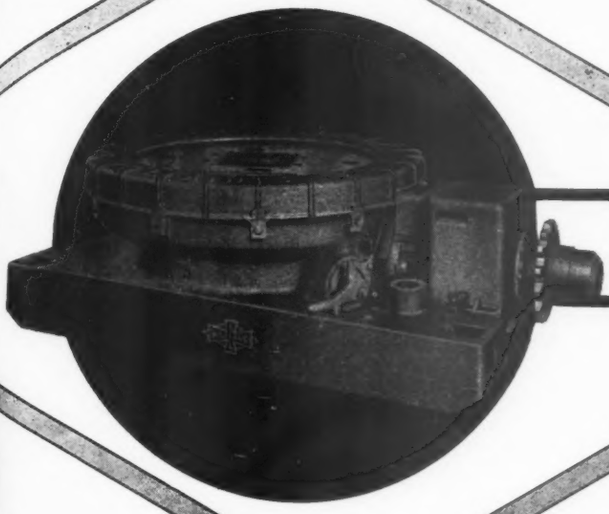

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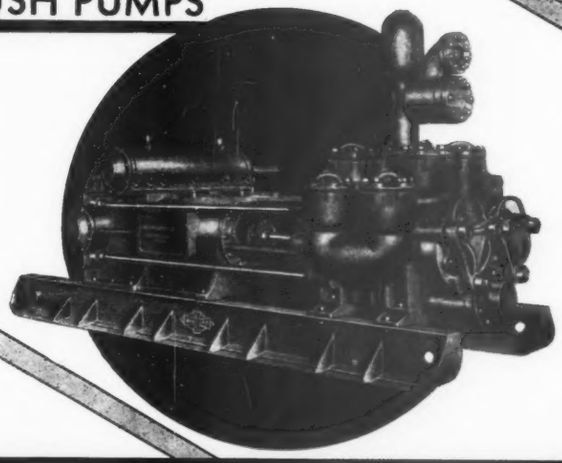

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Selective Plugging by Smokes in Air-Gas Drive*

By R. F. NIELSEN and S. T. YUSTER†

The Pennsylvania State College

● **Abstract.** The use of aerosols such as dusts or smokes for selective plugging in air or gas-drive operations seems a likely possibility, just as aquasols, such as wax dispersions, have served as selective plugging agents in water drive. A number of fine powders having ultimate particle sizes down to a fraction of a micron were tried, but sufficient dispersion could not be obtained by simple means to give selective plugging in the desired permeability range. Smokes of paraffin, stearic acid, rosin, and ammonium chloride prepared by a condensation method showed selectivity in the range from 90 to 700 md. Observations were made on the tendency of the smokes to stick to pipes and connections. It was found that the greater the capacity of the air or gas stream to cool the vapor of the smoke material, the less the tendency of the smoke to stick to connections. Factors involved in the generation of smokes, such as thermal balance and design of apparatus for field use, are discussed.

THE use of smokes in selective plugging in air-gas drive has been considered as a possibility in past discussions of this problem.[1] Aqueous dispersions such as wax emulsions have been used for several years as selective plugging media in water flooding. It therefore seems reasonable that gaseous dispersions, or "aerosols", such as smokes or dusts, might be used in a similar way in air or gas drives.

The use of smoke involves a number of difficulties not encountered in the use of aqueous dispersions. In the first place, smokes must be manufactured directly in the air or gas line at or near the injection wellhead. Smokes are much less stable than liquid dispersions, and show greater tendency to stick to pipes and connections. The rate of coagulation with increase of particle size is greater than that for aqueous dispersions, making it more difficult to obtain the proper particle size for selective plugging. If the smoke is made from organic materials such as waxes or resins, the smoke must be below the melting point of the material as soon as it is generated. The material should preferably be soluble in some cheap solvent or chemical, since it may be desirable to unplug the sand at a later date. The composition of the gas or smoke from the standpoint of explosion hazards must also be considered.

● **Use of powders.** The first laboratory experiments were with powders dispersed in an air stream. Some of the powders tried were talc, whiting, and Silene EF (a calcium silicate produced by Pittsburgh Plate Glass Company). The dust was picked up by an air stream and blown up a vertical piece of pipe at low linear velocity to allow the larger particles to fall back. Radial cores that had been loaded with brine and crude oil and airblown over night were used. These cores were from the Oil City area and ranged from 90 to 2000 md. dry permeability. Although the effective permeability of the 2000 md. core could be cut down 60 to 80 per cent by these powders, the permeability of the remaining cores could not be reduced much, the maximum being 20 per cent in the case of a 600 md. core. The plugging took place within a fraction of a minute, and prolonged treatment produced no appreciable further decrease, even though a thick layer of powder was deposited on the cores. The talc (Stupakoff's "Blue Star") and Silene were slightly more effective than whiting but whiting has the advantage of being soluble in dilute acids.

On the basis of ultimate particle size one would expect better plugging by these powders. The ultimate particle size as given by the manufacturers is of the order of a few tenths to less than one-tenth micron for a large portion of the material. The average pore diameter calculated theoretically, assuming 14 per cent porosity, is 8 microns for a 10 md. core and 60 microns for a 600 md. core. Apparently much more drastic means of dispersion are necessary, such as the use of explosives as in some types of smoke candles. The latter seems rather impractical though not impossible to set up in an air or gas injection line. Attempts to disperse the powders further by passing the dust stream between high voltage electrodes were unsuccessful, but this is no indication that some kind of electrical dispersion could not be accomplished.

● **Smokes made by condensation.** As the possibility of plugging with powders seemed to be limited, for the time being, to excessively high permeabilities, it was decided to try smokes prepared by either chemical or condensation methods. Some common examples of the former are burning magnesium ribbon or any material that leaves an ash, uniting ammonia with hydrogen chloride in an air stream, or passing a readily hydrolyzable material such as titanium chloride into moist air. The condensation method, as the name implies, involves sudden cooling of the vapor below the melting point of the material. A good deal of work, both experimental and theoretical, has been done on such smokes by various investigators. The effect of conditions of formation on particle size, rates and theories of coagulation, and change of particle size with time, are among the things studied. A good summary, with references, may be found in the book "Smoke" by Whytlaw-Gray and Patterson.[2]

The condensation method, being the simplest, and most applicable to such things as waxes and resins, was tried first. A sketch of the laboratory apparatus is shown in Fig. 1. The material was heated in the smoke pot S, while the air or gas stream passed over it, until the vapor pressure was sufficient to produce a smoke when diluted with the cold gas. Since any smoke, to be of use in the field, must pass through pipes and connections without too much deposition, the smoke in all experiments was passed through 50 ft. of ¾-in. pipe with several elbows, before it entered the core holder, C.

A number of radial cores of varying permeabilities were mounted together in each run, with those of lowest permeability at the upstream end. A pet cock at the downstream end was opened slightly to allow some of the smoke to escape. This arrangement was made to insure having about the same smoke concentration on all the cores so that the degree of selectivity could be determined. A pressure differential of 20 cm. of mercury was kept across the cores, the flow

TABLE 1

Effect of smoke plugging on conductivity of dry cores at atmospheric pressure.

Core number	1	2	3	4	5	6	7	8	9
Permeability in mud	8	12	90	200	250	275	350	420	675
Relative conductivity after rosin smoke, per cent	..	..	100	66	40	47	..	32	16
Relative conductivity after stearic acid smoke	..	..	100	82	66	69	66	62	50
Relative conductivity after brushing off and back-flowing	..	..	100	100	88	93	88	84	66
Relative conductivity after paraffin smoke	..	..	50	7	2	10	0.6	0.8	1.6
Relative conductivity after ammonium chloride smoke	100	94	70	80	62	62	70	57	42
Relative conductivity after brushing off and back-flowing	100	94	70	80	80	72	80	72	51

†Division of Petroleum and Natural Gas Engineering, The Pennsylvania State College, State College, Pennsylvania.

[1]References at end of paper.

*Presented at the Ninth Technical Conference on Petroleum Production held at the School of Mineral Industries, The Pennsylvania State College, State College, Pennsylvania, November 2 and 3, 1945.

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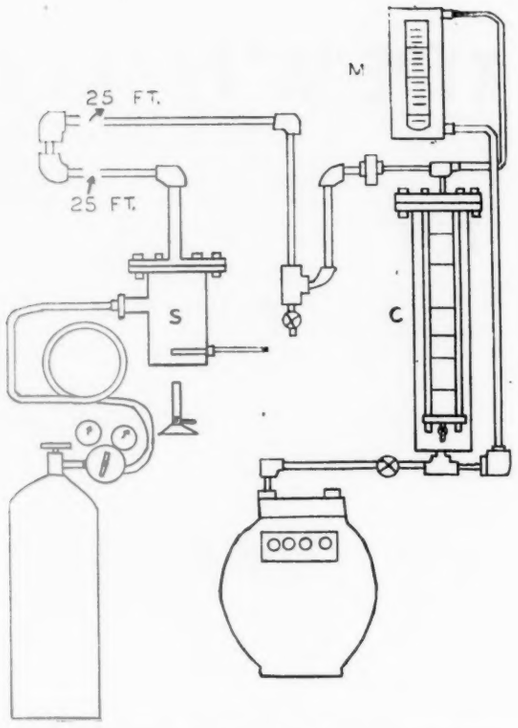

FIG. 1. Apparatus for smoke plugging experiments.

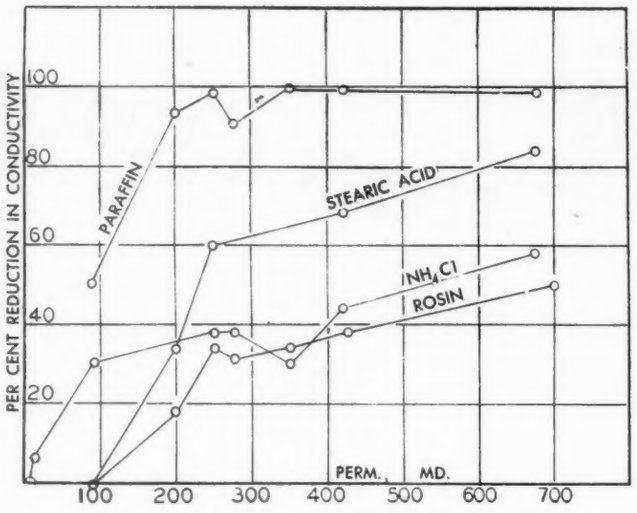

FIG. 2. Effect of smoke plugging on dry cores at

being from inside out. Table I shows the results of experiments on dry cores at atmospheric pressure. The relative conductivity after plugging is given as per cent of the original conductivity. Fig. 2 is a plot of the results given in the table. The cores were extracted and dried between runs, so as to restore the original conductivities.

In the cases of the stearic acid and ammonium chloride smokes, a heavy layer of the white powder was deposited on the cores. In order to see whether any appreciable amount was firmly lodged in the pores, the cores were brushed off with a test tube brush and backflowed. As seen in the table, the conductivity rose somewhat after this treatment. The ammonium chloride apparently penetrated more than the stearic acid, for brushing and back-flowing did not increase the conductivity as much as in the case of the stearic acid. These crystalline smokes formed more of a deposit in the pipe than the wax or rosin, but the amount of deposit was much decreased in experiments described below. One objection to ammonium chloride is the possibility of corrosion, but this might be kept down by the injection of a slight excess of ammonia or an amine.

The rosin seemed to give the best selectivity. It also gives quite a stable smoke and does not deposit nearly as much on the pipe as the crystalline materials. Unfortunately, there is some decomposition while the material is being heated, as evidenced by much frothing, and by the deposition of a small amount of a resinous liquid. Very little was required to cause plugging, and no deposit could be seen with the eye on the sand face, but the ends of the cores looked as if a liquid had penetrated slightly. In the case of the paraffin, no deposit could be seen, even though the plugging was almost complete on all but the least permeable cores.

As would be expected, the more permeable the core, in general, the greater the percentage decrease in conductivity, for the amount of smoke deposited in a given sand will be proportional to the cumulative volume of air injected into it. The laws of filtration would be expected to apply. This was discussed by Yuster and Calhoun[1] in connection with selective plugging by liquid dispersions. The general trend of the curves of Fig. 2 is very similar to that of curves for plugging with liquid dispersions.

Subsequent experiments using the apparatus of Fig. 1 were performed with a nitrogen pressure of 75 to 100 lb., and the same pressure differential (20 cm. of mercury) across the cores as before, and a back pressure at the outlet end. In these experiments the cores were loaded with brine and Pennsylvania crude oil and air-blown for several hours before the plugging tests. The brine contained 80 grams NaCl and 36 grams $CaCl_2H_2O$ to a liter, a composition roughly similar to the oil field brines in this locality. It was noticed that there was very much less deposit on the pipes and connections than in the experiments run at atmospheric pressure. The overall plugging results were similar to those with dry cores. Cores of low permeability were not cut down appreciably in conductivity, whereas a 2000 md. core was cut down by over 90 per cent. The results for cores in the range 100 to 600 md. were somewhat erratic, the conductivities being cut down by 25 to 80 per cent, without such a clear cut relation as in the case of dry cores. This may be because of solvent action of the residual oil on the plugging material, and Jamin and end effects that change in the course of the experiments. Stearic acid, paraffin, and rosin were used in this series of experiments.

It is difficult to say how to prepare a core to simulate the sand face on an injection well that has been in operation for a number of months or years. It seems likely that the dry cores would more nearly resemble such a sand face than any cores that could be prepared in a reasonable length of time containing brine and oil.

● **Factors in design of apparatus.** One of the problems in the preparation of smokes by dilution of the vapors with air or gas is the cooling of the smoke. That is, the gas stream must cool the vapors below the melting point of the smoke material, otherwise liquid will condense in the apparatus and pipes and interfere with both the generation and passage of smoke. A calculation can readily be made to see what the maximum weight of smoke material per cubic foot of gas would be if the only heat transferred to the gas was due to condensation and cooling of the vapor of the smoke material. For stearic acid, rough data obtained in the literature showed that 300 calories per gram were required to heat it from a solid at its melting point to a vapor at 150° C or 360 calories to heat it to a vapor at 250° C. The heat capacity of a standard cubic foot of air is about 9 cal. per degree Centigrade, so 350 cal. would be required to heat it from 25° as room temperature to 64°, the melting point of stearic acid. It should therefore be possible on this basis to vaporize about a gram per standard cubic foot or 2 lb. per 1000 cu. ft. Taking the molecular weight as 284, the stearic acid could

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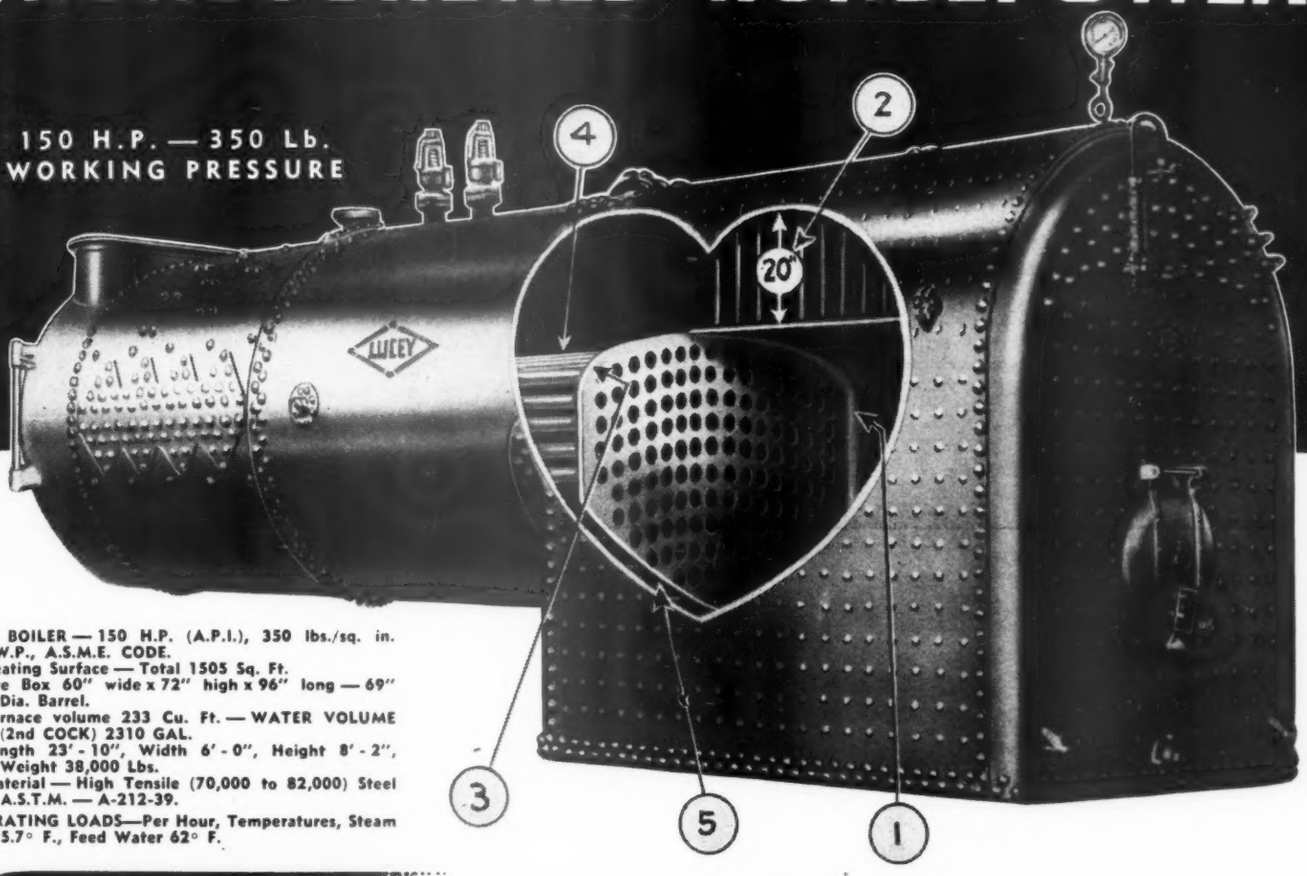

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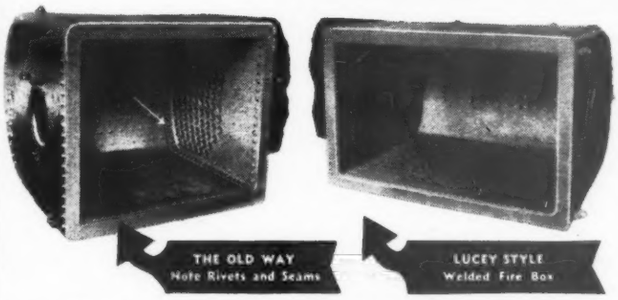

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be kept at a vapor pressure of $760 \times \frac{1}{284} \times \frac{22.4}{28.3}$ or about 2 mm., corresponding to about 190° C. or 375° F. (A plot of vapor pressure data from the literature yielded the empirical equation $\log_{10} p = 5.126 - (917/t)$ where t is in degrees centigrade, for the range of interest.) With the gas under pressure, a proportionately higher vapor pressure would be necessary to obtain the same smoke concentration on the basis of a cubic foot at atmospheric pressure.

Actually, in an apparatus made entirely of metal, there is a large amount of heat transfer to the gas. This is especially true if the walls are thick and a large volume of material must be kept hot. In fact, with a large smoke pot intended for field use, of the same type as the smoke pot of Fig. 1, it was found impossible to supply enough heat to keep the wax hot and at the same time avoid heating the smoke. In some recent laboratory experiments the smoke generator consisted of a Pyrex test tube of about 1 in. O.D., with a side tube sealed in at about 1½ in. from the bottom. An asbestos shield was placed around the tube just below the side tube. Carbon dioxide was the gas used, and this was throttled from the tank pressure (about 900 lb.) through a valve placed as near the smoke generator as the connections would allow. In this way most of the cooling effect due to the expansion could be utilized. As estimate of the cooling capacity can easily be obtained from a Mollier diagram for carbon dioxide, found in a handbook of refrigeration. Dense smokes of paraffin, stearic acid, and "Opal Wax" (Dupont's hydrogenated castor oil) were made with this generator at about 1 cu. ft. a min., and could probably be made much faster. The upper part of the tube remained colder than room temperature while the material in the bottom was heated to 500° F. in the case of paraffin and stearic acid and 700° in the case of opal wax. A very small flame from a Bunsen burner was sufficient to keep the smoke material hot. Stearic acid smoke from this generator, using carbon dioxide throttled to near atmospheric pressure, was tried on a series of cores, and the plugging results were entirely similar to those of other experiments. Also it was noticed that there was not nearly as much powder deposited on pipes and connections as with air or nitrogen in the all metal apparatus.

With regard to modifying this small generator for field use, it could possibly be made of a piece of 1½-in. or 2-in. pipe with some means of thermally insulating the bottom from the top, such as a ring of circulating water or a short section of cement or plastic joining two pieces of pipe. A connecting reservoir for feeding more smoke material into the generator as the material is depleted would have to be set up. A common method of making smoke is to allow the material to drop on a hot metal surface. It seems that it would be more difficult to control the conditions by this method than by the one just described, and that there would be more danger of decomposition of the material.

The foregoing is a digest of what has been done to date in this matter of selective plugging by smokes. Future experiments will be along some of the lines of attack that were mentioned, with emphasis on the design of an efficient and simple field apparatus.

● **Summary.** 1. Laboratory experiments on the use of dusts and smokes for selective plugging have been described.

2. Dusts were made from commercial powders having ultimate particle sizes as small as a fraction of a micron, but they could not be sufficiently dispersed by simple means to give selectivity in the permeability range desired.

3. Smokes made by a condensation method showed a selectivity as expected from the laws of filtration.

4. Some factors in the preparation of smokes as related to thermal balance and apparatus design were discussed.

● **Acknowlegments.** The writers wish to express their indebtedness to The Pennsylvania Grade Crude Oil Association for support of a portion of this work, and to R. B. Bossler of the Brundred Oil Corporation for assistance and advice on some of the experiments.

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2. Whytlaw-Gray and Patterson, *Smoke*, Edward Arnold & Company, London, 1932.

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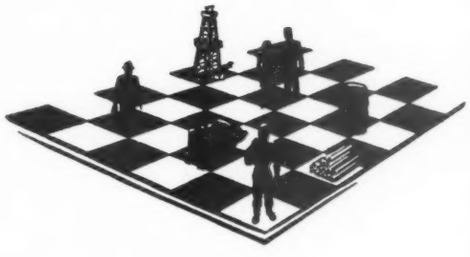

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Practical Economic Problems of Secondary Recovery*

By J. PAUL JONES** and HUGH RICH†

THIS paper is intended to treat with some of the practical economic problems of secondary recovery, the pitfalls to be avoided if possible, and the better operating practices as experienced from operations in the Bradford oil field.

Early methods of flooding were largely the result of accidents. Casing and tubing that had been left in the wells for many years rusted so that the fresh water in the formations above the oil sand finally broke through and ran down to the bottom of the hole where it penetrated the oil-sand formation. These accidents were recognized by an increase in the production of adjoining oil wells. When this condition was noticed the operators then drilled oil wells in a circle close around the flood well and created what is generally known as a circle pattern flood.

Later this haphazard method was improved by the introduction of the line flood. This consisted of two rows of oil wells staggered on both sides of an equally spaced line of water-intake wells extending across the property. This method succeeded in obtaining a larger quantity of oil per well than the circle flood method. It was expanded by drilling a second and third line of oil wells in a staggered position converting the first rows of oil wells into water wells when the water and oil ratio became abnormal. This method was known as the line flood.

The method that has been in use during a decade is to drill alternate rows of water and oil wells spaced in such a manner that each oil well receives flood water from four directions. This is known as the 5-spot method and is obtaining larger quantities of oil per well than any other method.

● **Recoverable oil most important factor.** Regarding the economics of the repressuring of an oil sand that has been depleted by primary methods, the most important factor to be considered is recoverable oil. In the older water-flood areas it is sometimes possible to estimate the recovery to be expected on any particular property by past experience from an old circle flood. In any event, much information can usually be obtained from one of the neighboring properties. This information is usually supplemented by information obtained through the analysis of core wells. The number of core wells to be taken would depend, of course, upon the size of the property under consideration. We assume that water wells will eventually be drilled on the corners of the property so that without any knowledge of proper spacing, etc., we will have four locations that we can core in, locations that would later fit in with any development program that might be adopted. In case we feel that four core wells will not give sufficient information, we could drill one or more in the center of the property at locations that would not be very far from any locations that might be determined to be correct later on.

The analysis of these cores will provide a knowledge of saturation of the sand body and its permeability. In our country a saturation of less than approximately 37 per cent in considered to be not suitable for initiating a water-repressuring program. This does not mean that if some part of the sand body has less than 37 per cent the whole sand is unsuitable for water-flood operations, as it is entirely possible that a large percentage of the total sand body contains a higher saturation. Nor will the 37 per cent hold true in other areas. Core analyses of sands in West Virginia and maybe elsewhere report considerably lower saturations and yet have been successfully water flooded. On the other hand, there are conditions where the saturations are above 37 per cent and no results have been obtained from water flooding. These discrepancies may be due to the methods of obtaining cores and analyzing them for saturation. We still have much to learn in that respect.

In equipping the input wells we should attempt to eliminate the lower saturated sand from the pressure medium. The sealing off of this low-saturated sand is very important, because our experience shows that this type of sand will take a large percentage of the water introduced into the well with little or no resulting recovery. This is very important because of the high cost in introducing water into barren sand and in turn pumping this water from the oil wells could very easily mean the difference between a profitable and unprofitable operation.

The type of packer used in cementing off the pay sand is important. It is sometimes found desirable to treat the sand face of the input well after a number of years of use. If the anchor packer type is used it may limit or even prohibit the application of any type of treatment later on. For this reason some type of packer should be used that will leave an unobstructed sand face.

● **Permeability ranges and spacing.** In Pennsylvania we consider any sand adaptable for water flooding in which the range between the high and low permeability values is within the range of 1-6. Some attempt is made to raise this ratio by corrective shooting. However, the size of the drill hole limits us somewhat in that respect. The permeability determines the return of flow of the water introduced, and it has always been our objective to have an even flow of water through all sections of the sand. A perfect water flood is one in which the oil from all the sections of the sand is driven into the oil well at the same time. In this case the depletion of an oil sand would be marked by the complete exhaustion of the oil and the pumping of 100 per cent water simultaneously. We have never been able to achieve this condition.

I am not able to tell you how much money should be spent in this exploratory work. This is a matter of individual opinion. I might be satisfied with spending $10,000 if the stakes are large enough whereas another operator might think that he couldn't do a good job without spending much more. In the final analysis the sand conditions found from preliminary core data should be the determining factor.

From the information obtained from the core analysis we now determine on the proper spacing to use in the development of the property. This to a great extent is tied in with the results of our saturation and our permeability tests. Generally speaking, a sand of low permeability should have closer spacing than a sand of high permeability, all other factors being equal. Saturation is also a factor that must be considered in the spacing. I believe that by the use of longer spacing there is some recoverable oil lost by the lensing out of some sections of the oil sand, also possibility by the bypassing of small pools of oil. In areas of high development cost, however, it is entirely possible that we would save more on the development costs than could be recovered from the additional oil to be obtained by a shorter spacing. Much thought should be given to the matter of spacing because on a 140-acre quarter section a spacing of 440 ft. by 440 ft. would require a total of 85 wells whereas a spacing of 330 ft. by 330 ft. would require a total of 145 wells, so that you can see the additional investment required for shorter spacing may mean the difference between a good or bad investment.

● **Economic property life variable.** After we have completed the necessary exploratory work and are reasonably satisfied that the sand will flood, and have determined the most economical spacing, we must satisfy ourself that the development will be a profitable investment. To determine this we must assume an average price we will receive for our oil during the life of the flood. The average price times the total estimated recoverable oil will, of course, give us our

**Director of production, Pennsylvania Grade Crude Oil Association, Bradford, Pennsylvania.

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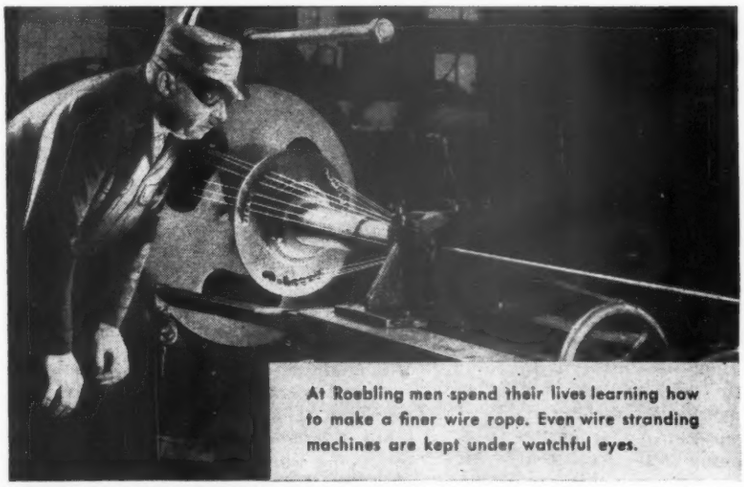

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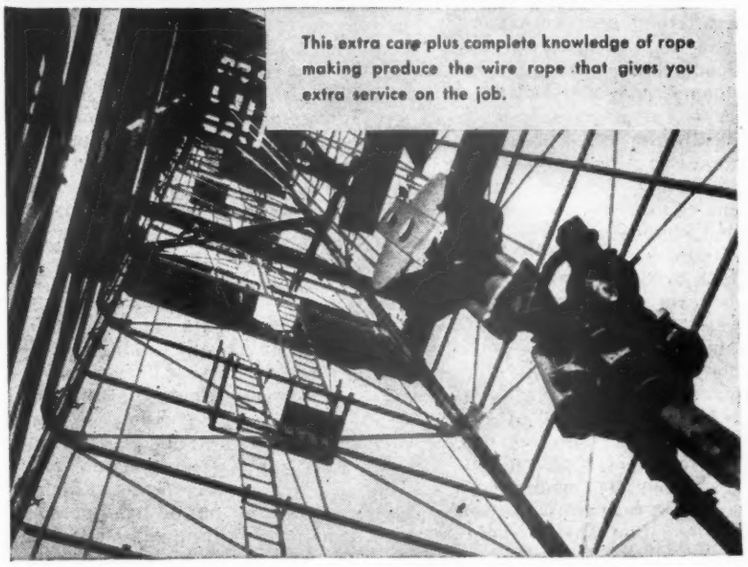

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total estimated gross income. Experience has proved that the economic life of a property is a variable figure. It might range from 5 to 15 years and is greatly determined by the efficiency and thoroughness of the initial exploratory and development work. This lack of thoroughness and inefficiency has resulted in many properties in our Bradford field being prematurely abandoned because of such mistakes as corrosive water, plugging off of pay sands, faulty installations of equipment, and high water-oil ratios.

Ordinarily the largest factor involved in development cost is the drilling. This is governed largely by the depth of the oil sand and the price per foot paid in the local area. To these costs we must add shooting, the oil, gas, water lines, and tankage, also the water-repressuring system.

The kind and size of the water plant itself is dependent upon the volume of water used, the pressure needed, and the quality of water available. The size and cost of this water plant is a matter of personal judgment. We have plants in our field that to me appear to be nothing but endless banks of engines and pumps. We also have smaller ones that can be set into a box 5 ft. by 5 ft. by 5 ft. and seem to be nothing more than sewing machines. Their cost ranges from $4 to $7 per bbl. of daily output. In other words, a 1000-bbl.-per-day unit should cost from $4000 to $7000. We have found that in the Bradford field the continuity of pressure on our producing sands is very important. Although we do not know exactly what takes place under the ground, we do know that shut downs of long duration have resulted in a permanent loss of production. I can quote innumerable instances in which the breaking of an engine shaft or the shutting off of water supply for any particular reason has reduced the daily oil production a considerable amount. When the pressure is reapplied, the response is usually slow if any and the former peak is never reached. For this reason it might be wise to give consideration to dual installations of pressure-plant equipment. The proper treatment of input waters to stop corrosion will also eliminate shut downs to a great extent.

The cost of the oil lifting medium is also a matter of judgment of the particular operator. There has been a considerable number of properties in the last few years that have been equipped to flow all their production. This would result in a material reduction in the operating cost if found practical to use. In areas where low-priced oil is to be produced it may be the determining factor, and its use should be gone into very thoroughly. However, if it is found necessary to use pumping equipment, then, of course, we must add to the development cost such items as powers, jacks, rod lines, etc.

Now that we have estimated our total income and what it will cost to develop the property we must see if there will be enough money left over to operate the property and still have a little left over for me. I am not going to attempt to tell you men what items go into operating cost. You are as fully aware of these items as I am. I do believe, however, that when a property is at its peak production you will find that lifting costs are practically the same irrespective of the area assuming, of course, the depths are the same.

Cost of repressuring water based on 4500 bbl. a day throughput. Original source of water approximately one mile from pressure plant.

Raising water and delivering to pressure plant	$0.00300
Treatment, aeration, chlorination, lime and complex phospate	0.00110
Supervision (analysis, etc.)	0.00044
Pressuring	0.01030
Total cost per bbl. of water	$0.01484
If this water was deaerated add	$0.00140
Total	$0.01624

● **Operating costs involved.** There are some operating costs involved in water flooding with which you may not be so familiar. I invariably find that the largest item of expense on my properties is labor, and looking at the picture today, it does not look as though this can be cut any. The next largest items of expense are maintenance and operating supplies. In a water-flood operation all equipment is going 24 hours a day and usually at full load. In a good many cases the equipment is terrifically overloaded. This tends to make for repeated replacements and it is up to the operator to see that the best materials and equipment are installed in the original development. The third largest item is property taxes. This is another item that, to say the least, cannot reasonably be expected to be reduced. Water costs are also an important item. In the West here there seems to be only two sources of supply. One involves the damming up of streams and using the surface water. The treatment of this water to take out any sedimentary particles, stop corrosion of pipes, to kill algae, and to take out any chemical constituents that might be harmful to the sand is a costly operation. This also holds true if the operator uses the salicious lime water, because this water may require just as extensive a treatment. Another large item of expense is fuel. Should you be blessed with sufficient supply of gas on your property you would be one of a fortunate few. The motive power that you use is to a large extent dependent upon local conditions. Some localities have cheap electric power, some have cheap gas, and in some it is necessary to use fuel oil. They are all costly if they must be purchased.

To these operating expenses we must, of course, add our overhead. I cannot give you any idea of what these will be, because I have never yet seen two companies who charge the same amount per barrel for overhead. This overhead cost, however, is a legitimate cost, and every barrel of oil that is produced should stand its proportionate share.

Now that we have in our minds the most important items of cost and expense, we take an old envelope out of our pocket, figure out how much income we are likely to get from this operation, deduct from this income all our development costs and our operating expense and overhead, and see what we have left. If this is a property to be purchased we must have enough to buy the property and still come out with a little left over. We then weigh the profit we expect to get against the money that we must invest in order to make a profit and from this determine which we would rather have, the money in the bank now or the profit later on. This may sound very simple, but in practice the planning and developing of a secondary-recovery operation is not all a bed of roses.

● **Engineering advice necessary.** The secondary-recovery operator must watch out for many economic pitfalls. The risk involved in this type of operation is very hazardous, and until research has developed more knowledge of just what takes place down in the sands these risks will continue to exist. Any secondary-recovery operation needs very close supervision. The input rate of individual input wells and the water-oil ratio of the producing wells will give you considerable knowledge of what is taking place in your sands. This information should be gathered and used. Do not hesitate to employ expert engineering advice and be sure to give him tools to work with by making core data available. It may save you considerable money in the end.

You can see from the data presented in this paper that secondary recovery entails additional expense not usually incurred in the ordinary production of crude oil. The apparent success of water flooding in the Bradford and Allegheny fields can be attributed to a number of factors that other fields may not have. We were endowed with conditions very favorable for this type of operation. Nature gave us an abundant supply of good water. Our producing formations are comparatively shallow, and short strings of casing are used. The sands are relatively uniform, not too open, and highly saturated. And last, our oil has a paraffin base of high lubricating value and consequently we receive a high price for it.

● **Secondary recovery research needed.** The picture here in Texas may not be as favorable. You may find that economic conditions may prevent the application of secondary recovery on a large scale until such a time as the price structure is more conducive to this type of operation. However, there remains in your sands a vast amount of oil that only secondary-recovery methods will recover. Yet even the most efficient secondary-recovery methods known today will still leave behind approximately one-third of the oil originally in place. Only research and development work, with the experience it entails, will produce this residual oil, but if we are able by these means to reduce successfully the residual oil content of our sand by only a small per cent the results will be worthwile.

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THERE IS NO ECONOMICAL SUBSTITUTE FOR QUALITY

North Coles Levee Pressure Maintenance Project Control of Gas Expansion*

By **W. J. TRAVERS, JR.,** Richfield Oil Corporation

THE North Coles Levee oil field is located on the floor of the San Joaquin Valley, approximately halfway between the cities of Bakersfield and Taft. It is the most westerly of a group of deep fields that were discovered in the years from 1936 to 1939, largely as a result of seismic exploration. Others in order of discovery are Ten Section, Greeley, Rio Bravo, Canal, Wasco, South Coles Levee, Strand, and Paloma. The South Coles Levee field is immediately adjacent to North Coles Levee and is on a roughly parallel structure separated from North Coles Levee by a narrow but deep syncline. Within the productive area of North Coles Levee the surface consists largely of flat bottom lands comprising a portion of the delta area of the Kern River. The field derives its name from a levee constructed for the purpose of controlling admission of Kern River flood waters to Buena Vista Lake in the year 1888 by Henry Miller of Miller and Lux, and James B. Haggin, one of founders of Kern County Land Company. The original location of the Bakersfield-Taft highway through this area was along the top of the old levee. A portion of the road was re-located and straightened in 1936, but the old levee still stands. The levee bears the name of an early rancher who also operated a ferry across the slough at this point.

The structure of the North Coles Levee field is that of an elongated dome with an almost east-west trend. The apex is located in the NE¼ of Section 32, T. 30S, R. 25E, M.D.B. & M. The field is about 18,500 ft. long and 9,000 ft. wide. Although there is no surface evidence of structure, folding is reflected in all beds below the Recent river fill. The discovery well was located after intensive work with reflection seismograph in the early part of 1938.

Formations from the surface to 4000 ft. consist of Recent, Tulare, and San Joaquin Clay beds. Due to the absence of coring at shallow depths, stratigraphic boundaries for these formations have not been established. This Quaternary-Upper Pliocene interval is predominantly sand down to about 1800 ft. and largely shale with a few lenticular sand lenses from 1800 to 4000 ft. From 4000 ft. to about 7000 ft., the formation is predominately blue shale of Etchegoin-Pliocene age. There are a few lenticular sand bodies. Numerous normal faults are present in this interval. These faults seem to die out with depth and with one or two minor exceptions are unidentifiable below the base of the Etchegoin. In several localities some of these faults combined with otherwise favorable structure and discontinuity of the sand bodies, have resulted in the entrapment of dry gas. These dry gas sands range in depth from 4000 to 5600 ft. and have an aggregate areal extent of 400 acres. From 7000 ft. to a little below 9000 ft., the formation consists of Upper Miocene beds of the Monterey series. This is the deepest penetration of any well drilled in North Coles Levee. The upper 800 to 1000 ft. of Miocene consist of gray brown to brown shale with no sand bodies of any significance. These shales become increasingly compact and indurated with depth and are immediately underlain by an interval of about 200 ft. of very hard cherty brown shale, which is known as the "Chert Zone." Near the top of this zone is an outstanding electric log marker known as the "N" point. It is the most consistent and widely used point for contouring in deep producing areas of the central part of the valley. Below the Chert Zone lies a sandy series that has a total thickness of about 1000 ft. A number of local names have been applied to this sand and to various subdivisions of it, but the whole interval is usually known as the Stevens Sand. The name Stevens was taken from a small railroad siding on the old McKittrick railroad adjacent to the discovery well of the Ten Section field. Permeable sands in the North Coles Levee field first occur at points from 200 to 400 ft. below the top of the Chert Zone. The oil saturated zone has a mixmum thickness of 850 ft., of which about 70 per cent is sand.

The North Coles Levee field was discovered by Richfield Oil Corporation with a completion on November 27, 1938, of Tupman Western No. 1. This well is now designated as Coles Levee "A" 32-32. An initial production of 3018 bbl. of 49.7 deg. gravity oil per day and 18,000,000 cu. ft. of gas was obtained from the interval 8406-8677 ft. Gas-oil ratio was 6000 cu. ft. per bbl. As demonstrated by subsequent development, this producing interval included 160 ft. of the original gas cap and 110 ft. of oil producing sands below the original gas-oil interface.

The second well, Coles Levee "A" 52-32 located 950 ft. east of the discovery well, was completed on April 9, 1939, for an initial production of 1984 bbl. of 48.4 deg. gravity oil per day and 14,600,000 cu. ft. of gas. Gas-oil ratio was 7400 cu. ft. per bbl. The producing interval in this well was from 8534 to 8792 ft. The shut-off point in the second well was 130 ft. lower stratigraphically than that in the discovery well, but was still high enough to permit entry of free gas from the gas cap sands.

The third well, Coles Levee "A" 12-33 located 3600 ft. east of the discovery well, was drilled completely through the productive section. This well has the greatest stratigraphic penetration of any drilled to date. By continuous coring the oil-gas contact was located at 8565 ft. and the oil-water contact at 9150 ft., 300 ft. and 850 ft., respectively, below the first permeable sand. From this well and information obtained from deep wells on nearby structures, it appears probable that there is little permeable sand for several thousand feet below the base of the Stevens sandy zone. This well was completed on November 23, 1939, for an initial production of 1578 bbl. of 34.2 deg. gravity oil and 1,293,000 cu. ft. of gas. The cementing point was selected sufficiently low to exclude the gas cap sands. The top of this producing interval is about 200 ft. stratigraphically below the shut-off point in the discovery well. Completion of the third well with a gas-oil ratio of 800 cu. ft. per bbl. definitely demonstrated the presence of low ratio black oil production within the pool.

Subsequent to this completion, wells within the areal extent of the original gas cap were cemented through perforations below the oil-gas interface and completed with uniformly low gas-oil ratios of 600 to 800 cu. ft. per bbl.

In Fig. 1 the original conditions are shown on a North-South cross-section. The top line represents the "N" point marker. The first permeable sands come in irregularly from 200 to 400 ft. below the "N" point. The water string shut-offs are placed not at a stratigraphic point, but at the top of the first permeable sands. The second line on the section represents the base of a fairly continuous shale body and the top of the main producing sand. The interval from the shut-off point down to this shale body contains very little sand on the crest of the structure, but changes laterally to include some fairly good sand bodies on the flanks and on the eastern plunge. Production from these zones has generally been separated from that of the main zone by packers placed in cemented blank sections or by inclusion of only a single zone in a given well. This interval is known as the Upper Western Zone. A very good development of the sand in the lower portion of this interval on the south flank of the structure is referred to as the "25-33" sand. A good development of the upper portion of this interval on the easterly plunge and north flank is known as the "21-1" Zone. These designations both refer to the well in

*Presented before American Petroleum Institute Pacific Coast District Division of Production, Los Angeles, April 11, 1946.

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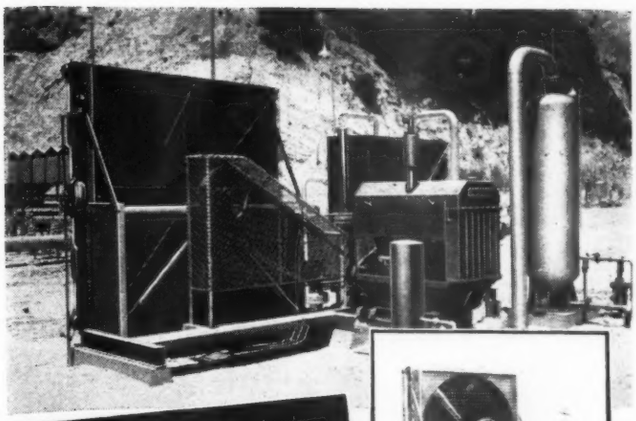

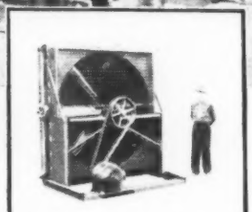

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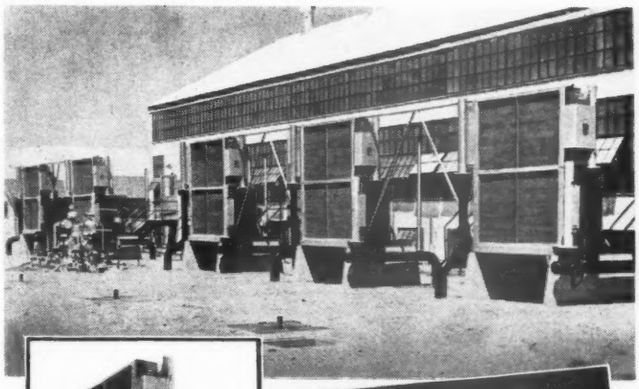

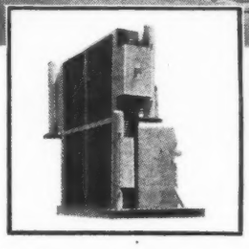

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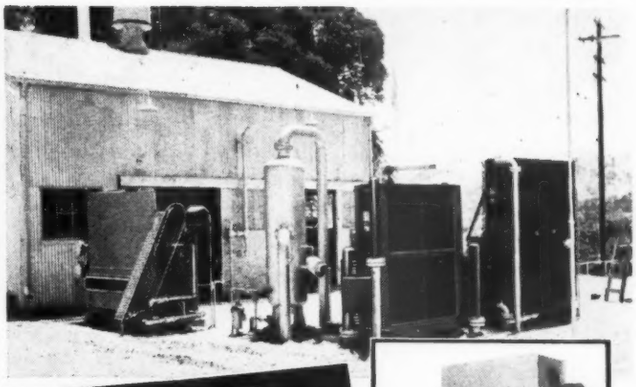

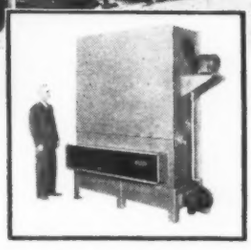

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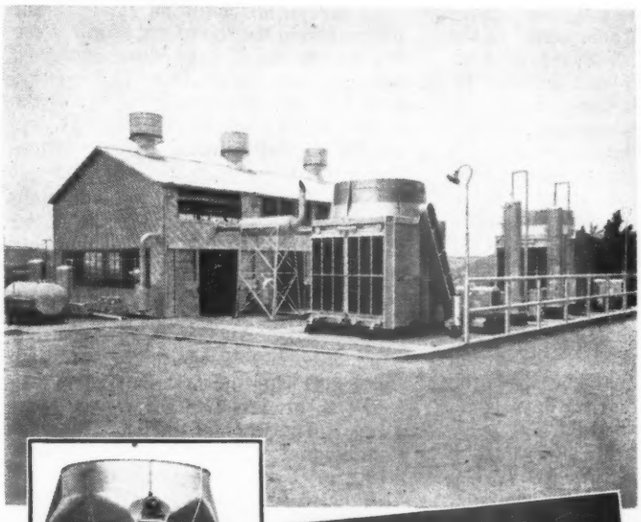

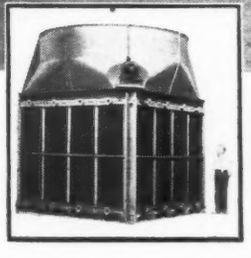

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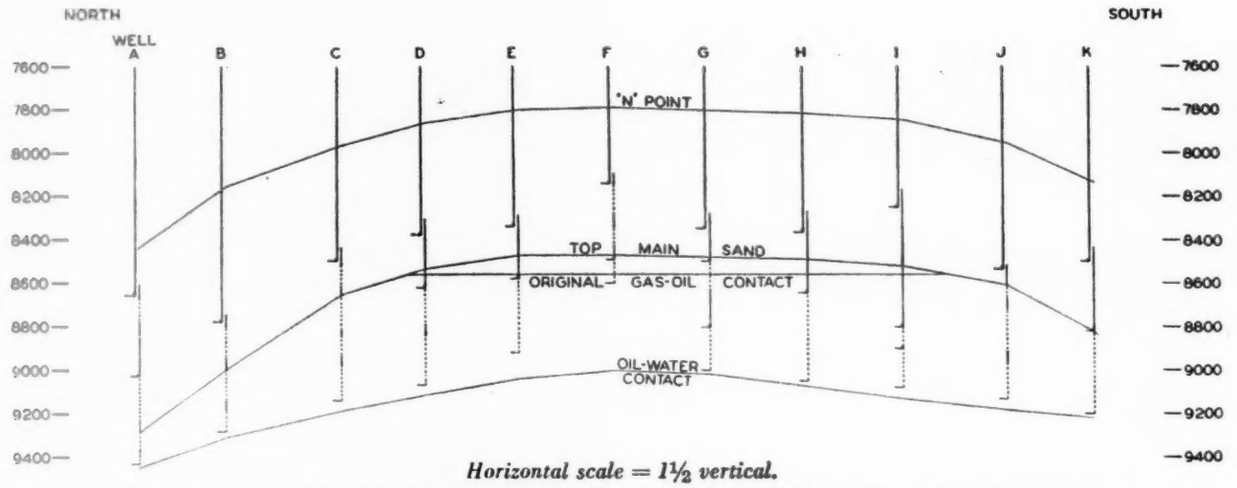

FIG. 1. Generalized north-south cross-section North Coles Levee field showing original completions.

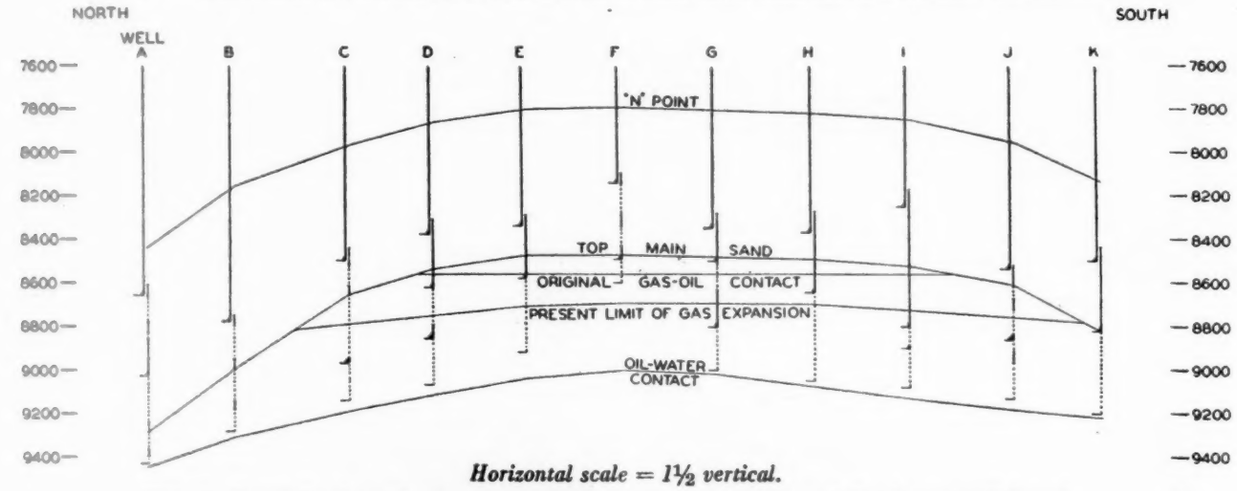

FIG. 2. Generalized north-south cross-section showing completions following remedial work.

which the particular sand was first produced. The sand development below the next line in Fig. 1 is known as the Lower Western Zone. It consists predominantly of permeable sands with a few relatively thin and apparently discontinuous shale bodies. These shale bodies are of very little value in correlation and are apparently so limited in areal extent that they have only a minor influence upon the vertical and horizontal movements of reservoir fluids. About 300 acres on the crest of the structure was originally occupied by gas cap. There is no faulting of magnitude sufficient to be discernible from electric log correlations, or from cores, below the top of the Chert Zone. Behavior of reservoir fluids, however, suggests that a permeability barrier of some type trending N 60° E across the South portion of Section 29, T. 30S, R. 25E exists. This barrier may be the partial result of a fault of small displacement.

Sand permeabilities throughout the Upper and Lower Western Zones vary through a wide range from 0 to 7500 millidarcys, but average a little above 100 millidarcys.

Following the completion of the third well, a rapid development program was instituted. A total of 69 wells were completed by the end of 1941. Since that time development has proceeded at a slower rate. To date, 72 wells have been completed in the Lower Western Zone, four wells have been completed in the Upper Western (25-33 Zone), and 21 wells have been completed in the "21-1" Zone. These wells have required a drilling time which has averaged 60 days. The casing program has consisted of a surface string of 11¾-in. or 13⅜-in. casing cemented at 1400 ft., a water string of 8⅝-in. or 7-in. casing cemented through the Chert Zone at the top of the first permeable sand at depths ranging from 8300 to 9000 ft., and a 6⅝-in. or 5½-in. liner. The drilling time is divided into three roughly equal intervals. The first 20 days is required to drill from the surface to 8000 ft., or just above the Chert Zone. The second 20 days is required to drill through the Chert Zone. In the hardest part of this interval, rock bits frequently make as little as 5 ft. The third 20 days is required for running, cementing, landing and testing the water string, drilling into the zone, running and cementing the liner and completion operations. The average overall cost of the completed wells is about $100,000.

It is from the Lower Western Zone that the principal withdrawal has occurred and it is this zone that has been selected for the principal effort in pressure maintenance.

In the initial condition sands in the interval from the top of the Lower Western Zone to the oil-gas contact contained free gas and condensate. The interval from this contact down to the top of the bottom water initially contained 34 deg. gravity oil with solution gas at a formation ratio of 600 cu. ft. per bbl.

During the period of rapid development, no information was available on the rate of gas expansion or possible edge water encroachment. The producing interval of the Lower Western Zone wells included the sands from a short distance below the oil-gas interface to a point 20 to 50 ft. above the oil-water contact. During the first four years, the field was produced in the conventional manner. Allocation of the pool allotment to individual wells was such as to maintain a relatively even pressure pattern. This close pressure control minimized the possibility of gas coming into a pressure low. Reservoir pressures showed a slow and wholly normal decline. There was no evidence of edge water encroachment. The initial high ratio wells were shut-in to conserve reservoir energy. After a sufficient number of wells had

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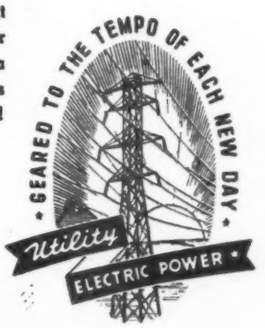

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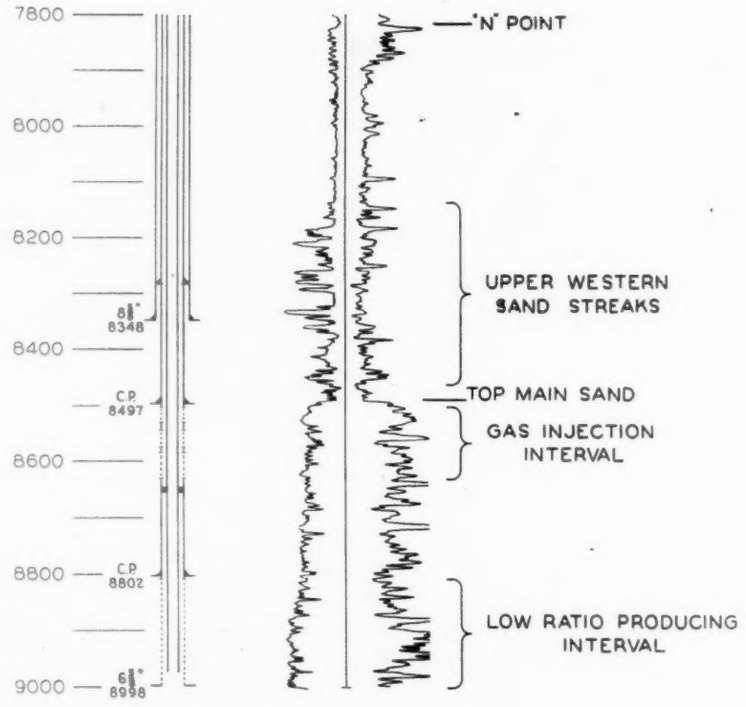


FIG. 3. North Coles Levee field typical electric log showing combination gas injection and producing wells.

been completed to determine the reservoir characteristics, an intensive study was made to select the most advantageous method of exploiting this relatively deep and high pressure, low permeability reservoir. No pressure maintenance experience was available from any California fields, but the results of such operations in the Gulf Coast area indicated the desirability of such a plan. Disappointing results from the later stages of production operations of similar California fields such as North Belridge and Kettleman Hills was another important influence.

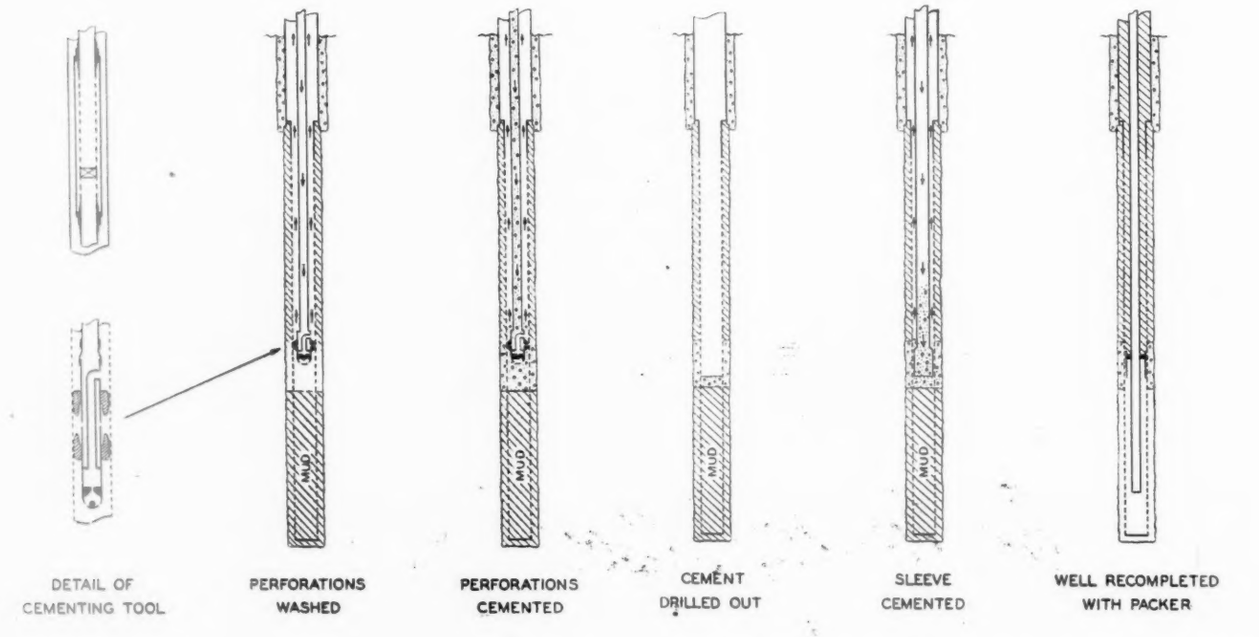
The 3600-hp. compressor plant was completed and the first gas was injected on November 19, 1942. By January 1, 1943, sufficient gas was being injected to maintain pressures and complete pressure maintenance has been adhered to since that time. The dry gas zones in the Etchegoin formation have been partially developed and have been drawn upon for make-up gas to supplement residue dry gas from the absorption plant. Injection rates have varied from 20 and 35 million cu. ft. per day at a pressure of 3200 to 3400 lb. per sq. in. The results observed to date have been most encouraging. The flowing life of the wells has been prolonged. The pattern and rate of gas cap expansion has been favorable.

Expansion of the gas cap was noted early in the producing life of the field. At the present time gas has expanded to a position represented by the lower line in Fig. 2. Remedial work has been performed to lower the top of the producing interval. There is still no discernible movement of the bottom water. Gas is currently being injected at a surface pressure of 3300 lb. per sq. in. into five injection wells. The injection interval is confined to the top 150 ft. of the Lower Western Zone. Four of these wells are used exclusively for gas injection and one is a combination injection and producing well. In the straight injection wells, gas is injected through the 2½-in. tubing. In the combination well, gas is injected in the annulus between the 2½-in. tubing and a 6⅝-in. protective string while the well is produced through the 2½-in. tubing.

The completion of the combination injection and producing well is illustrated in Fig. 3. An 8⅝-in. water string is cemented above the first permeable sand streak. A 6⅝-in. liner is perforated through the upper 130 ft. of Lower Western Zone and cemented from that point back to the shut-off. Another cemented blank section is provided from the bottom of the injection zone to a point about 200 ft. above the bottom of the producing zone. The bottom 200 ft. is the producing interval. A 6⅝-in. protective string was run and cemented just above the top of the liner. This string serves the dual purpose of preventing leaks through or possible failure of the 8⅝-in. water string and permitting the running of a conventional packer to separate the injection and producing zones. The annulus between the 6⅝-in. and

FIG. 4

FIG. 5



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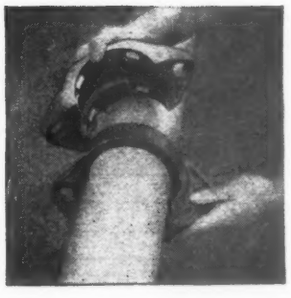

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8⅝-in. casing was left full of mud and the 8⅝-in. casing side outlets are left open so that any leakage of gas can be quickly detected. Electric log of this well shown to the right of the mechanical details is typical of wells drilled in the gas cap area of the structure.

Excluding the two initial wells, the expansion of gas cap gas first appeared in Coles Levee "A" 38-28 in February, 1941. The second and third wells to be reached by expansion of the gas was Coles Levee "A" 18-29 and Coles Levee "A" 32-33, both in July of 1941. The increase in ratio was slight at first. After February, 1942, a marked tendency towards increased ratios was apparent.

The first method of gas-oil ratio control consisted of shutting in wells where ratios had climbed above 2000 cu. ft. per bbl. By April, 1942, six wells were shut-in for this reason. It was then apparent that some means of gas-oil ratio control that would avoid the loss of producing wells would be necessary efficiently to carry out the objectives of pressure maintenance.

When the original liners were run, blank sections 20-ft. to 40-ft. long were provided opposite shale bodies with the thought that these might be cemented at a later date and utilized for the setting of packers for gas-oil ratio control. A program was instituted early in 1943 to follow out this plan. The procedure was as follows:

A bridge was placed just below the section to be cemented. Cement was pumped behind the blank interval through a cement retainer run on tubing and set in the blank section. Cement was then cleaned out inside the liner and the effectiveness of the blank section cement job was tested with a formation tester. Sufficient tubing or drill pipe was run dry to produce a hydrostatic differential of about 2000 lb. per sq. in. when the tool was open. If the test showed no leak, a surface pressure of 1500 lb. per sq. in. was applied to the annulus making a total differential of 3500 lb. per sq. in. One or more cement jobs were usually necessary. Remedial work on eight wells was performed in this manner. A total of 16 cementing operations was required to produce effective jobs, an average of two cementing jobs per well. The cost of this type of remedial work varied from $13,000 to $27,000 per well, averaging $19,500. This method was on the whole satisfactory in wells where we were fortunate enough to have placed blank sections in the proper intervals. As expansion of the gas cap continued, wells were found that had not been provided with properly placed blank sections. In four of these instances, the oil liners were pulled from the wells and new ones were run equipped for cementing at the proper points. The procedure in this type of work was as follows:

The perforations were first thoroughly washed with a bentonitic mud. Reservoir pressures would not permit the use of oil as a circulating fluid. Hydrochloric acid or mud acid was then used to attempt to dissolve the mud cake behind the liners. The liners were then cut in sections varying from 20 ft. to 100 ft. in length and removed. Several hours of jarring was frequently necessary to loosen the pieces. In a number of instances, oil was spotted behind the fish to aid in the recovery. After the liner was removed, the hole was underreamed and a new liner run, equipped for cementing at a point substantially below the bottom of the expanded gas cap. The average cost of the four remedial operations performed in the above manner was $68,000 per well. This cost was excessive and was largely due to the difficulty experienced in fishing. Due to this experience the desirability of developing a method for effecting a cement job in a perforated interval without removing the liner was developed.

A perforation washing and cementing tool was designed as shown in Fig. 4. The top portion of the tool consists of a bypass collar that is run in the string at the point of equalization of the cement. This collar consists of a perforated tubing nipple enclosed by a sleeve of slightly largely diameter. A baffle is placed in the perforated interval. This arrangement permits the use of rubber plugs in front of and behind the cement slurry to prevent contamination of the cement by the circulating fluid. Prevention of contamination is very important where

FIG. 6. Well performance curves of typical well in North Coles Levee field.

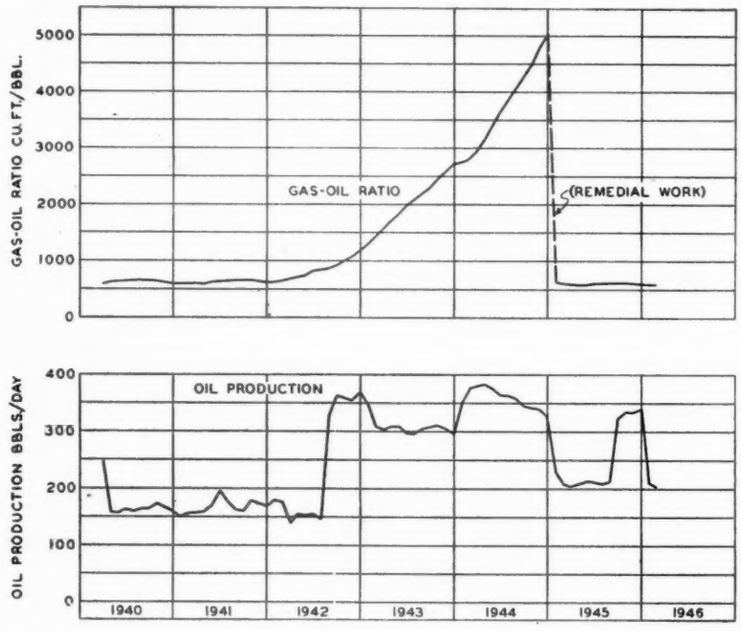
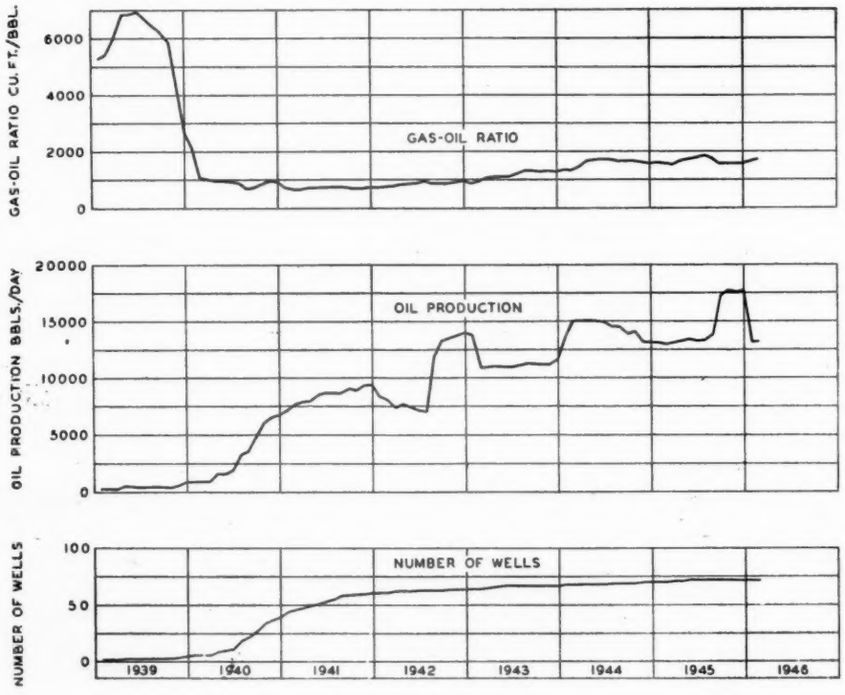


FIG. 7. Reservoir performance curves in western zone, North Coles Levee field.



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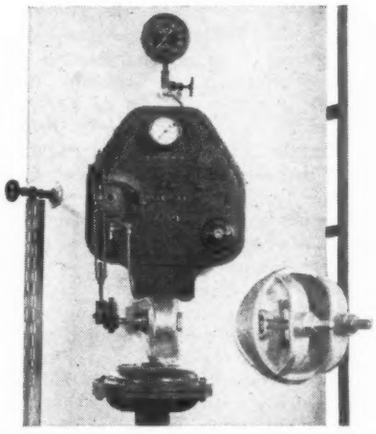

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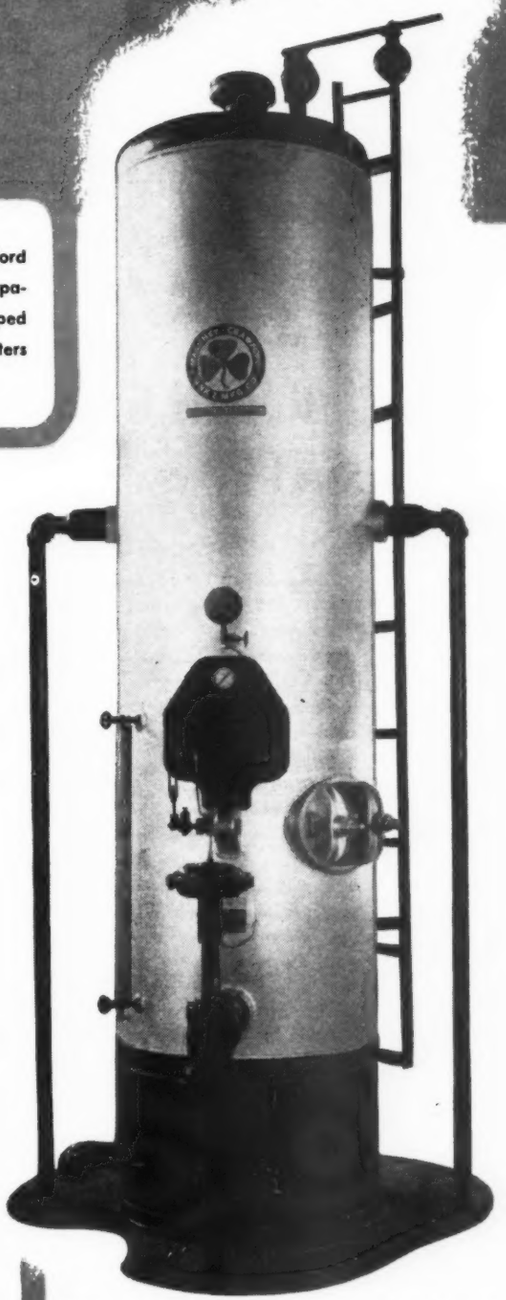

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small batches of cement are used for relatively deep cementing jobs. The theory of turbulent flow plus our experience indicates that in a 9000 ft. hole, the first 15 or 20 sacks and the last 15 or 20 sacks of a batch of cement will be markedly contaminated by the drilling mud if the cement is not isolated. Where batches as small as 50 sacks are used, very little uncontaminated cement is left by the time the cement reaches the intended point. The lower part of the tool consists of a tubing mandrel with opposed swabs mounted as indicated. The fluid circulated down the tubing string is forced out through the perforations in the liner through a hole in the mandrel between the swab rubbers. A bypass is provided to prevent a swabbing action when the tool is pulled from the hole. This is necessary to prevent disturbance of the cement after it has been pumped into place. The bypass is equipped at the bottom with a float type back check valve to prevent the cement from traveling down and up through the bypass.

The well is first killed with water. The water is then changed to a rather viscous bentonitic mud and the interval to be cemented is thoroughly washed. The tool is then lowered to the bottom of the interval to be cemented and the mud is replaced with water above that point. The mud left in the bottom part of the hole has proved to be very effective in preventing the settling of cement below the desired point. The cement slurry is then mixed and pumped in the tubing. When this slurry starts out through the liner perforations, the tool is slowly raised over the interval to be cemented. Circulating velocity is maintained at a high rate. This movement of the tool is coordinated with the displacing operation so that the tool arrives at the top of the interval to be cemented when the cement reaches the point of equalization. No further circulating is done and the cementing tool is pulled from the hole.

After the cement has been allowed to set, a bit is run in and circulating fluid is changed back to mud. The cement is then drilled out to a point about 10 ft. above the bottom of the bridge as shown in Fig. 5. A very close fitting blank sleeve is then run, landed on the 10 ft. bridge remaining and cemented through tubing with a thin cement slurry. In 6⅝-in. liners, a 5½ in. O.D. Grade "A" steel sleeve has been used. The use of relatively soft Grade "A" steel will permit the removal of the cemented sleeve if necessary by a comparatively simple milling job. The hole is then cleaned out to bottom and the tubing is run, equipped with a conventional hook wall packer, which is set in the blank sleeve. After testing the packer, the sleeve, and the cement job simultaneously with pressure applied to the casing annulus the well is swabbed in and recompleted with the upper part of the former zone excluded. The annulus between the tubing and casing is left full of bentonitic mud and the casing side outlets are left open. Observation of the fluid level in the annulus will then quickly determine if a leak is occurring around the packer or sleeve and any gas leaks may be noted. Four remedial jobs have been performed in this manner. Three of these operations were successful on the first attempt. In the other instance, it is probable that the sleeve was cemented opposite a section of side tracked hole which had not been accurately logged. In this instance, the sleeve was milled up in 36 hours with 2 mills and another sleeve was cemented at a lower point. This second attempt was successful. The average cost of the above remedial operation has been slightly under $20,000 per well. The procedure described has made possible the securing of a zone separating cement job in a perforated interval for approximately the same cost as cementing a blank section.

A production curve of a typical well located at the edge of the original gas cap is shown in Fig. 6. The oil production of this well through a six-year period has varied from 140 to 385 bbl. per day. The gas-oil ratio was initially 600 cu. ft. per bbl. This ratio was maintained practically level until the early part of 1942 when a slight tendency to increase was noted. The gas-oil ratio climbed slowly at first and then more rapidly until a peak of 5000 cu. ft. per bbl. was reached at the end of 1944. A remedial operation was then performed and the productive interval of the well was restricted to the bottom of 200 ft. of the Lower Western Zone. The ratio dropped sharply and has subsequently remained practically constant again at 600 cu. ft. per bbl. In all, 16 remedial operations have been performed. In every case, the ratio has been reduced from a high point of 2000 to 5000 cu. ft. per bbl. to about the formation ratio of the black oil.

The combined effect of gas injection and remedial operations described are shown in Fig. 7. The lower curve depicts the number of wells completed in the Lower Western Zone. Beginning with one well in the early part of 1939, development progressed rapidly during 1940 and the early part of 1941 and more slowly thereafter. At the present time, 72 wells are completed in the zone, including the five injection wells. The average oil production of the pool is represented by the next curve. Rates varying from 10,000 to 17,500 bbl. per day have been maintained for the last four years. The top curve represents the pool gas-oil ratio. This was very high for the initial wells but dropped sharply with the completion of low ratio wells and the shutting in of the two initial wells. The ratio was then fairly constant for three years and did not rise above 1000 cu. ft. per bbl. until the early part of 1943. Up to the present time, the increase is still gradual and the ratio is still below 1800 cu. ft. per bbl. It is the purpose of the pressure maintenance program to maintain this slowly rising trend until the gas has replaced a very large proportion of the oil in the reservoir.

This plan will require many years of close control and a program of remedial operations for its accomplishment, but we are encouraged to believe that the results will more than justify the cost and effort. ★★★

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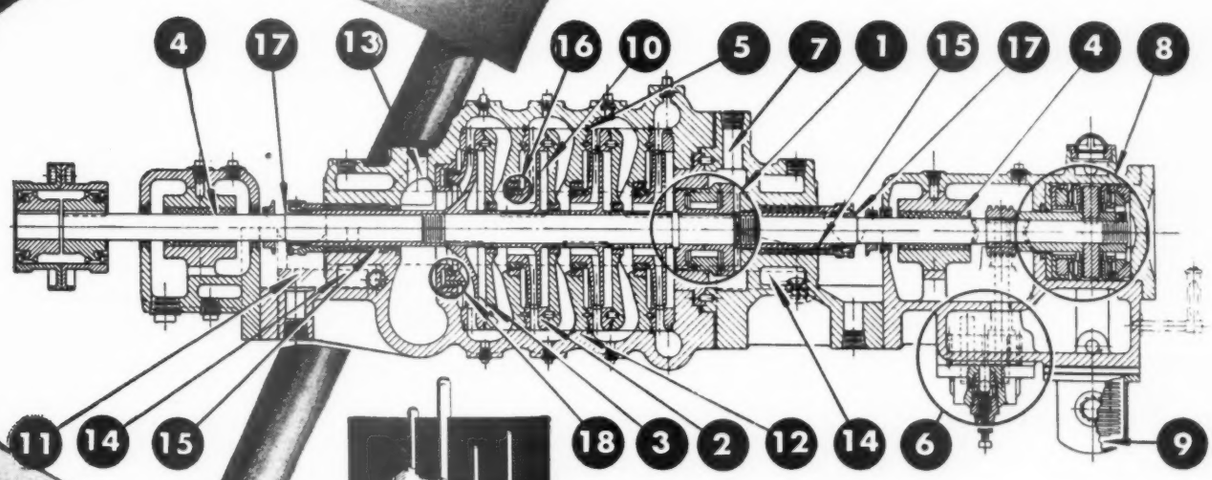

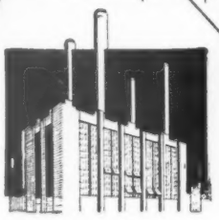

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Trends and Developments in Petroleum Production Engineering*

By **STUART E. BUCKLEY,** Humble Oil and Refining Company

● **Abstract.** This paper summarizes the important trends and developments in production engineering, particularly for the period since 1941. This period has had an important influence upon the trend of engineering development because of the fact that the high wartime rates of oil production afforded an opportunity for quantitative observation and evaluation of petroleum reservoir characteristics under controlled conditions.

It is the author's opinion that the most important development in petroleum engineering within recent years has been the inauguration of the transition from the qualitative to the quantitative stage. This transition is not complete but is in fact just sufficiently developed to be reaching the period of vigorous further growth and advancement. The groundwork for this quantitative stage has been built and the future should bring a degree of quantitative engineering control far surpassing expectations of a few years ago. This trend is illustrated with examples of technically controlled development and operation of selected oil reservoirs and the basic and applied research which forms the basis for the trend is briefly reviewed.

The suggestion is made that to keep pace with progress in the industry the technical man, engineer, or geologist, must recognize the necessity of abandoning qualitative thinking and must adapt himself to the more difficult task of quantitative study. Those unable to accommodate themselves to this progressive change will lose ground in the same manner as has occurred in many a manufacturing industry when the processes have advanced from art to science.

● **Introduction.** The purpose of this paper is to present for the returning veteran a brief review of developments since 1941 in petroleum production engineering. It is directed primarily to those items and trends that are thought to be significant and important to the geologists dealing with production in the technical sense. No attempt has been made to review the entire field of petroleum engineering. For example, no mention is made of advances in drilling techniques or equipment improvements. It is recognized that such items form an important part of petroleum engineering and that they have a direct bearing on the cost of finding and producing oil; however, such phases do not overlap the technical field of geology. This paper is concerned primarily with those matters in which the engineer and the geologist have a common professional interest, the mutual problems of development and exploitation of oil pools.

● **Effect of the war on production technology.** The war severely interrupted a vigorous activity in production technology; much promising research in progress in 1941 was discontinued and many technical field studies were curtailed because of diversion of geologists and engineers from their normal pursuits to the armed services or to other functions. Thus, while certain branches of science were greatly stimulated and phenomenally advanced during the war, including electronics and nuclear physics, no corresponding activity took place in the technology of oil production. It is probable that during the more than four years that have elapsed since the beginning of the war the technical progress in oil production has not exceeded one to two years' normal advance. Hence, those who have been away from the profession for three to five years have only a reasonable amount of new factual knowledge to assimilate. On the other hand, a significant development has begun to assume recognizable shape during this interim and it is important that the returning veteran recognize it, appreciate it, and accommodate himself to it.

It is possible that the returnee has here an advantage over those who have stayed too close to their jobs, burdened with added wartime responsibilities, and too confined to details to appraise critically the technological changes taking place in the industry. Although his war duties may have been such as to leave no time for thought of the technical details of geology, nevertheless his absence may have given the veteran an opportunity to consider his profession objectively with the detachment of an outsider.

● **The development of a quantitative production technology.** The significant development now under way is the transition from the qualitative to the quantitative stage of oil production technology. The development did not begin during the war, nor even immediately preceding it; it was hindered technically rather than promoted by the war-created shortage of scientific personnel. On the other hand, possibly of much greater and far-reaching importance than this temporary interruption was the sharp focus brought to bear by the war urgency on the need for quantitative accuracy instead of intelligent guesses in the operation of petroleum reservoirs. Not only was production technology forced into the limelight, but it was accorded an acceptance that hardly could have been foreseen a few years before. Industry committees, cooperating with state and federal regulatory agencies, gathered large volumes of technical data, calculated oil and gas reserves, and estimated maximum efficient rates of production for all important flush fields. The realization that maximum efficient production rates could be calculated with sufficient accuracy and assurance so that they could be used as the guide to production during a period of unprecedented oil demand, and the almost universal acceptance of the maximum efficient rate as a yardstick, brought to production technology a stature that it probably would not have reached in many years of peacetime operations. Along with the tremendously increased rates of production in certain areas, opportunity was afforded for quantitative observation of the effects of increased production on previously restricted fields. Thus, the effect of the war was not entirely negative in the technical sense. It made obsolete the qualitative approach, rushed the poorly prepared quantitative approach through a very short adolescence, and created an acceptance of production technology that places on the engineer and the geologist a responsibility that he must accept if the technical opportunities thus opened are to be exploited.

It is immaterial at this stage to trace the exact beginning of the quantitative application of scientific principles to oil production. A few isolated individuals made pertinent scientifically acceptable observations from time to time as long as 40 or 50 years ago. Their work was often overlooked or not appreciated and was more frequently forgotten than exploited. The environment was not yet ready for these energy bursts to set off a technical chain reaction. A gradual acceleration of the frequency of such studies continued until the 1930's, during which time the number of technologists doing significant research and engaged in technical field work became sufficiently large to produce a continuously significant and growing sicentific literature. Much of this work was qualitative and semi-quantitative. General principles were established, but their exact application to specific producing reservoirs was yet to come. This qualitative work was yielding ground rapidly to the quantitative toward the 1940's, when progress was interrupted in late 1941. Technology in oil production is

*Presented at the 31st annual meeting of the American Association of Petroleum Geologists, Chicago, April 4, 1946. This paper will be published complete in the July *AAPG Bulletin*, Vol. 30, Number 7.

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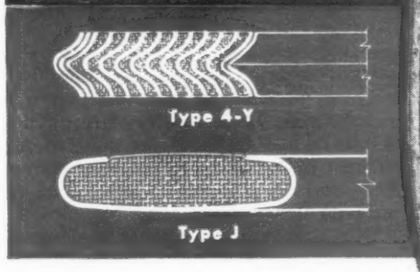

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now coming of age. The qualitative picture of the mechanics of oil reservoir operation is essentially complete. A fair start has been made on a quantitative understanding and evaluation. In the immediate future a tremendous acceleration should come in the quantitative study of every phase of oil reservoir development and exploitation.

● **Examples of quantitative technology.** In order to simplify discussion of the many overlapping and complex problems encountered in oil production, the various phases that must be quantitatively studied have been arbitrarily classified in the following sequence:

1. The fluid properties of the oil, gas, and water that occupy petroleum reservoirs.
2. The characteristics of producing formations.
3. The chemical and physical behavior of the fluids in their porous habitat.
4. The behavior of wells, including their testing, completion, production, and repair.
5. The characteristics and behavior of petroleum reservoirs.
6. The interrelation between reservoirs and their surroundings.

It is essential in any particular operation that accurate information be available on each of the subjects enumerated. Their mutual interrelation and interdependence must be determined for each specific reservoir if development and exploitation are to be undertaken on a sound basis. It is readily apparent that both engineering and geology are involved and that no sharp distinction can be drawn between the two.

By way of specific illustration of the importance of individual items in an overall analysis of a particular problem and the manner in which quantitative studies have been employed, several typical examples are reviewed briefly.

● **Fluid properties.** It has been known for many years that when oil is produced a reduction of volume occurs as a result of the escape of gas from solution. Devices for measuring the shrinkage and the amount of gas dissolved in the oil and methods of estimating the shrinkage have been reported in the literature from time to time. In many companies the determination of shrinkage factors and their use in estimating reserves has become routine. Seldom has the shrinkage factor been considered, however, as a controlling item either in reserve calculations or in the particular exploitation method employed to recover the oil from a pool. Quite recently, phenomenally high shrinkage factors have been encountered in several pools. In the North Lindsay pool in McClain County, Oklahoma, producing from the Ordovician at 11,000 ft., the shrinkage was found to be so great that only 0.44 bbl. of stock-tank oil is recovered when a barrel of reservoir oil is produced[1]. Several other deep fields have recently been found in which the solution gas-oil ratio approximates 2000 cu. ft. per bbl. and the shrinkage 50 per cent. When it is borne in mind that reservoir pressure decline can cause shrinkage of comparable magnitude in the oil remaining in the reservoir, it is clearly evident that this factor alone has an exceedingly important bearing on the results that might be obtained by reservoir pressure maintenance. In reservoirs of this type, the shrinkage factor is far more of an element in the ultimate recovery than a mere correction factor to be applied to reserve calculations.

Quantitative measurement and interpretation of the properties of hydrocarbon mixtures have other applications even more elementary. Several deep reservoirs produce light hydrocarbon liquids indistinguishable from crude oil at gas-liquid ratios ranging from 2000 to 8000 cu. ft. per bbl. Without quantitative information on the phase relations of such mixtures, needless expenditures are sometimes made in deepening or squeeze cementing to exclude excess gas when the only material present in the producing formation is a homogeneous gas or liquid of unusual composition.

● **Formation characteristics.** Quantitative measurements of formation characteristics, including the determination of porosity and permeability of cores, are routine, and well completions are

[1] "Oklahoma at Important Threshold With New Deep Pools," K. B. Barnes, *Oil & Gas Journal*, Vol. 44, No. 31, p. 76-80, December 8, 1945.

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usually made with confidence when complete core information is available. Ordinary core analyses, however, do not always tell a quantitative story. Comparison of well productivities with the permeabilities of the exposed intervals has in many cases yielded concordant results. In other cases, however, notably in California, actual well productivities have been far less than would be expected from ordinary permeability determinations on dried cores[2]. Although it has long been suspected that hydration of the producing formations, either by connate water or during drilling, is responsibile for the discrepancy, the quantitative effects for such hydration were not demonstrated until core permeabilities were determined with water instead of with air as the test fluid[3]. In some areas where commercial wells have been possible only with shooting, drilling of the producing formations with non-aqueous muds has yielded wells of comparable performance to shot wells. To know that a formation is permeable or impermeable and that it carries oil is no longer enough to guide well completions.

[2]"Permeability as Related to Productivity Index", N. Johnston and J. E. Sherborne, *API Drilling and Production Practice* (1943), p. 66-81.

[3]"Water Permeability of Reservoir Sands", N. Johnston and C. M. Beeson, *Petroleum Development and Technology, AIME Trans.* Vol. 160 (1945), p. 43-55.

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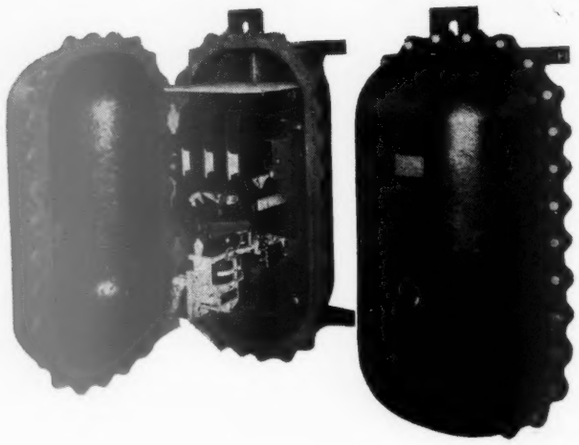

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● **Fluid behavior in sands.** So much research, both in laboratories and in the field, has been done on the mechanism of the flow of fluids through porous media that it is difficult to choose for illustration a specific outstanding item. However, to illustrate the importance of what may at times appear to be almost academic research, remote from immediate practical application, studies of capillary pressures in sands afford an interesting example. Such studies indicated that capillary pressures are closely associated with the amount of connate or interstitial water held in producing formations, and led to the suggestion that an indirect means could be employed for the determination of connate water contents of cores. Recent comparisons of this indirect method with results obtained by coring with oil have indicated that the method has considerable promise[4].

Connate water content of oil sands, like the shrinkage factor, is not merely a discount factor to be applied in reserve calculations, but may have a decided direct bearing on well productivity and the degree of oil recovery. Studies of secondary recovery operations have shown, for example, that under certain conditions excessive water content of an oil sand may make secondary water flooding impractical[5].

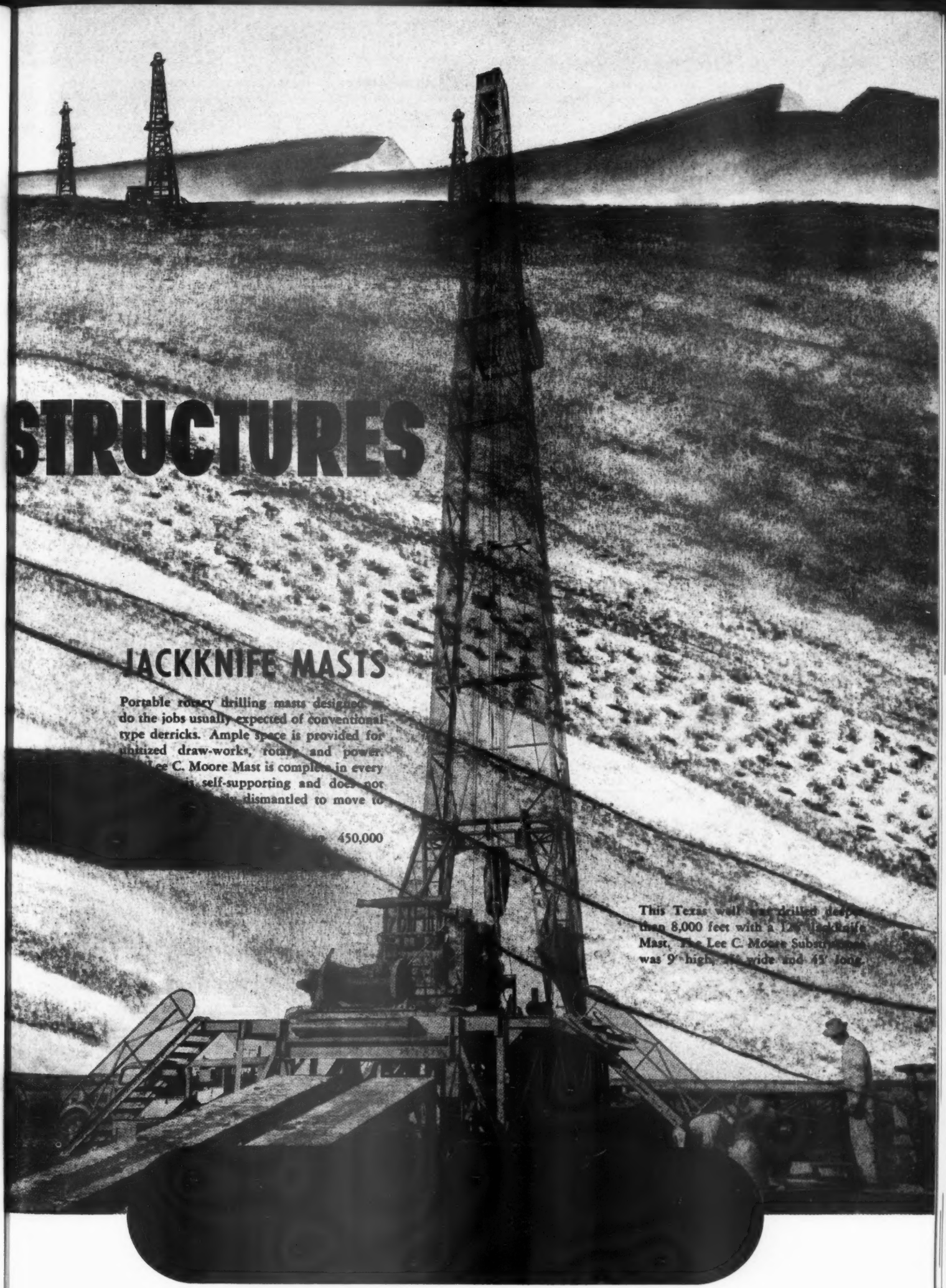
● **Well behavior.** Quantitative studies of producing formations and of the wells themselves are essential if wells are to be tested, completed, produced, and worked over at minimum expense. It is not sufficient to know that a well is a good or poor producer. The exact productivity factor, the productivity per pound pressure decline, and the relation between this factor and the capacity of the supposed producing interval provide important information on casing perforations, formation or screen plugging, cement seals, and other items having a direct bearing on the value of a well and its effectiveness in producing oil from a reservoir.

● **Reservoir behavior.** Quantitative interpretation of reservoir behavior has probably reached its highest development in water drive fields. During the war the net oil and water withdrawals from the East Texas field were so carefully controlled to maintain the reservoir pressure that although over 500 million barrels of oil were produced during the four years 1942-45, inclusive, the reservoir pressure at the end of the period was about the same as at the start.

Many excellent papers have been written on the quantitative relationships between reservoir pressure decline and water influx. Under proper application, such relationships can be relied upon with confidence to predict the performance of water drive reservoirs over extended periods and to determine the

[4]"Determination of Interstitial Water Content of Oil and Gas Sands by Laboratory Tests of Core Samples", J. J. McCullough, F. W. Albaugh, and P. H. Jones, *API Drilling and Production Practice* (1944), p. 180-188.

[5]"Role of Connate Water in Secondary Recovery of Oil", P. A. Dickey and R. B. Bossler, *Petroleum Development and Technology, AIME Trans.* Vol. 155 (1944), p. 175-183.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effects of oil production rates and water injection or production on reservoir pressure. Similar techniques are being used extensively by the U.S.G.S. in evaluation of underground water supplies and their rates of availability.

An outstanding example of the utility of quantitative analysis of water drive reservoirs is furnished by the Midway field in Arkansas[6]. Calculations showed that the natural water drive in this field, although appreciable, was not adequate to support the desired rate of oil production. Further calculations showed that by supplementing the natural water drive with injected water the pressure could be maintained or even increased. It was possible to determine accurately the rate of water injection required to maintain any particular reservoir pressure at any particular rate of oil production. Based upon this quantitative analysis, the operators were able with confidence to evaluate in advance the results of water injection and to inaugurate a program of pressure maintenance. Subsequent results have demonstrated the accuracy of predictions made before start of the injection[7]. It is obvious that in this case the mere qualitative knowledge that the field had a water drive, good, fair, or poor, would have been inadequate information on which to base an operating program.

● **Reservoir surroundings.** The quantitative interrelationship between a petroleum reservoir and its surroundings is well illustrated by a study of various Smackover pools in southern Arkansas[8]. The behavior of these pools and their rates of water influx were quantitatively determined with the aid of an electric device for solving the mathematical relationships involved. These studies revealed that the pools must compete for the available water supply in the Smackover formation and that the pressure decline of one pool will affect the pressures of other pools in the same formation. It was shown, for example, that production from the Magnolia pool will have a greater effect on the reservoir pressure of the Village pool than will the production from the Village pool itself. Without a quantitative analysis of the entire Smackover producing region, misinterpretation of the pressure behavior of individual pools might have led to mistakes in operations.

Another example of the relationship of the behavior of a pool to its environment is afforded by the Hawkins pool in East Texas[9]. Measurements made at various points in the basin showed that the pressure in the Woodbine sand had been lowered to an appreciable extent over a considerable area prior to discovery of the Hawkins field. One segment of the Hawkins field was found upon discovery to have the same initial pressure as that then existing in the Woodbine sand. The major part of the field, however, was found at the time of its discovery still to have a pressure corresponding to the original pressure in the Woodbine sand, some 280 lb. per sq. in. greater than the actual pressure in the vicinity of the field at the time of discovery. The quantitative pressure measurements showed at an early stage in the development of the field that the major portion of the Hawkins reservoir is effectively sealed off from the water in the Woodbine sand and that, unlike all other Woodbine fields, the major portion of the Hawkins reservoir has no water drive. This conclusion could not have been reached without quantitative measurements.

● **Present status of production technology.** It is not possible in a brief review of this sort to cover in detail all of the important developments in production technology. Those who are inter-

[6] "A New Application of Water Injection for Maintaining Pressure and Increasing Natural Water Drive", W. L. Horner and D. R. Snow, *API Drilling and Production Practice* (1943), p. 28-34.

[7] "Pressure Maintenance by Water Injection, Midway Field, Arkansas", W. L. Horner, *Oil & Gas Journal*, Vol. 44, No. 28, November 17, 1945, p. 185-190.

[8] "A Study of the Smackover Limestone Formation and the Reservoir Behavior of Its Oil and Condensate Pools", W. A. Bruce, *Petroleum Development and Technology, AIME Trans.* Vol. 155 (1944), p. 88-119.

[9] "Hawkins Field, Wood County, Texas", E. A. Wendlandt, T. H. Shelby, and John Bell, paper presented at *AAPG Meeting*, Chicago, Illinois, April 3, 1946.

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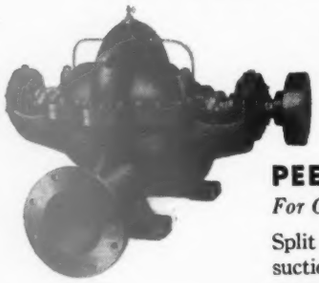

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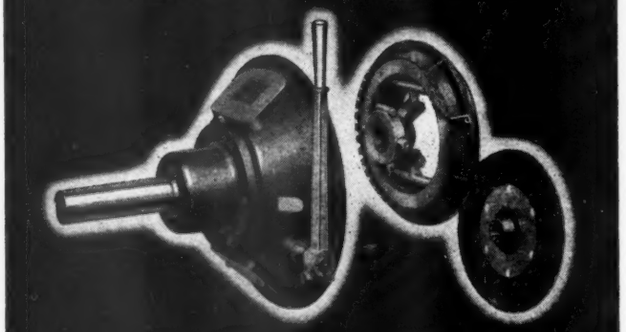

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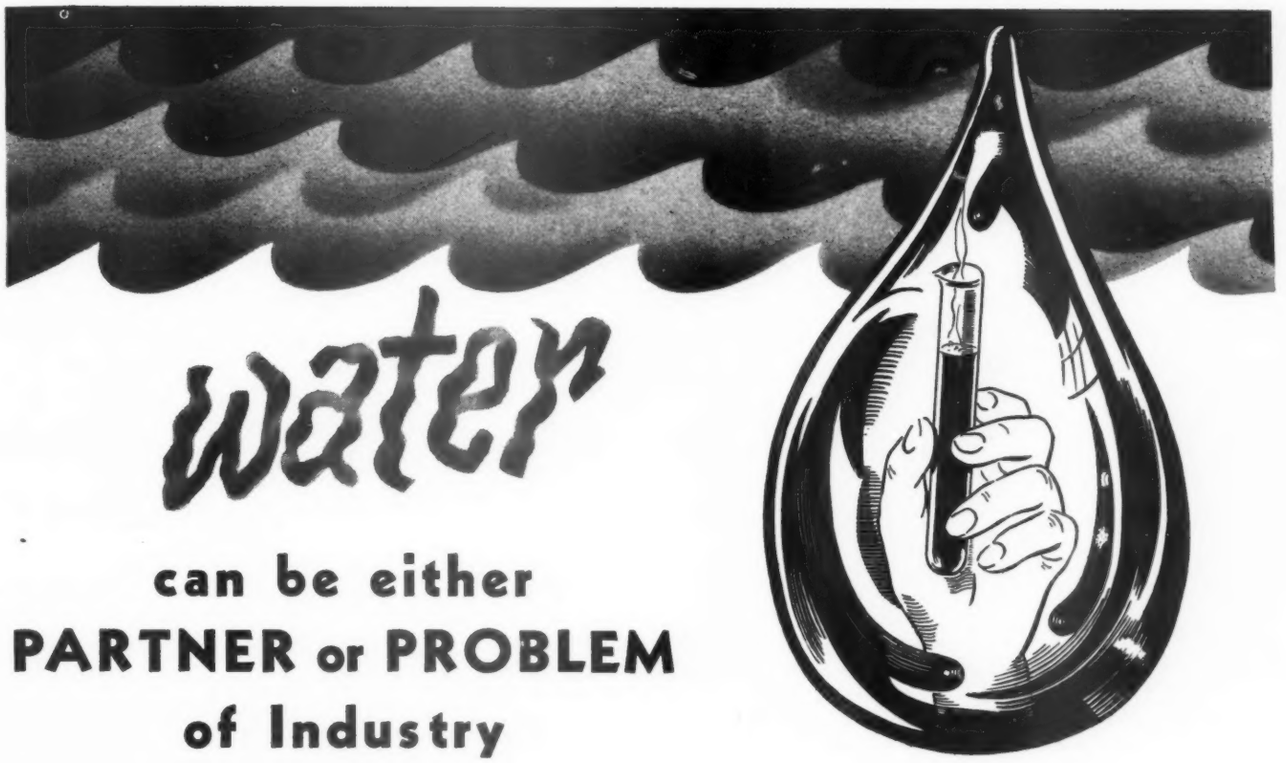

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ested in the details may find ample coverage of various items in the technical literature. The following, however, summarizes the present status along certain lines of particular interest and importance.

The thermodynamic properties, phase relations, and physical behavior of the hydrocarbons comprising oil and gas mixtures are now reasonably well understood both at high pressure and low pressure, and for condensate reservoirs as well as ordinary oil and gas reservoirs. Methods are in routine use for determination of the pertinent properties of such mixtures under reservoir temperature and pressure. The present state of development in this field is the result in part of excellent research sponsored cooperatively by the industry through the American Petroleum Institute and in part of research done directly by the industry. In this field of activity, guesswork is unnecessary. Both the methods and the technical understanding are available for providing quantitative answers to most of the problems that arise. For example, it is possible to determine accurately by appropriate test procedures whether a particular gas-liquid mixture exists in the reservoir as crude oil, as natural gas, or as a combination of both. If it is gas in the reservoir, it is possible to determine the extent to which condensation will occur in the reservoir with depletion and pressure decline, the composition of the condensing liquid, and the resultant changes in character and composition of the produced mixture.

The determination of formation characteristics is in a far less advanced state quantitatively, particularly from the standpoint of fluid content, than is the determination of the properties of the fluids. While determinations of porosity and permeability and to a lesser extent gas, oil, and water saturations are routine on cores, most wells are not cored and core recovery is frequently incomplete. Advances are being made in various logging techniques and interpretations and in control of drilling mud properties to reduce core flushing and contamination. The use of pressure measurements in connection with production and injection tests of wells is being used to an increasing extent to evaluate specific producing intervals.

The present state in this field must be described as only partly satisfactory. Progress is being made, however, through various lines of attack. As the geologist is directly concerned with this problem, his active cooperation in its solution is required.

Excellent research has disclosed fairly completely the fundamental principles controlling the heterogeneous flow of oil, gas, and water in sands. This information is being applied quantitatively to well completions and to operation of both water drive and gas drive reservoirs. Such application is based on laboratory flow tests of selected cores and field measurements. Progress in this field is proceeding at a rapid rate. Much less is known of the mechanism of flow in limestone of different porosity types.

Advances in well completion, testing, and repair have been principally mechanical or semi mechanical. Non-mechanical progress is dependent largely on further developments in evaluation of formation characteristics and fluid contents. Improved depth measurements, control of completion intervals, and isolation of selected horizons have advanced materially. The use of materials other than cement for exclusion of gas and water has progressed rapidly in some areas. Selective methods of testing and acidizing limited intervals are in use.

The identification and control of the type drive or recovery mechanism operative in a reservoir has reached a rather thorough state of quantitative development. In condensate reservoirs, gas drive, and water-flooding operations electrical models are being employed extensively to disclose sweep patterns and to control input and production rates to obtain maximum flushing.

In water-drive reservoirs, methods are now available and are being widely used for quantitative determination of the amount of water influx, its relationship to reservoir pressure, and the effects of oil production rates and water injection on reservoir pressure. A relatively recent advance in this field has been the development of an electrical analyzer for solving the necessary relationships without the tedium and the limitations of the difficult mathematics involved.

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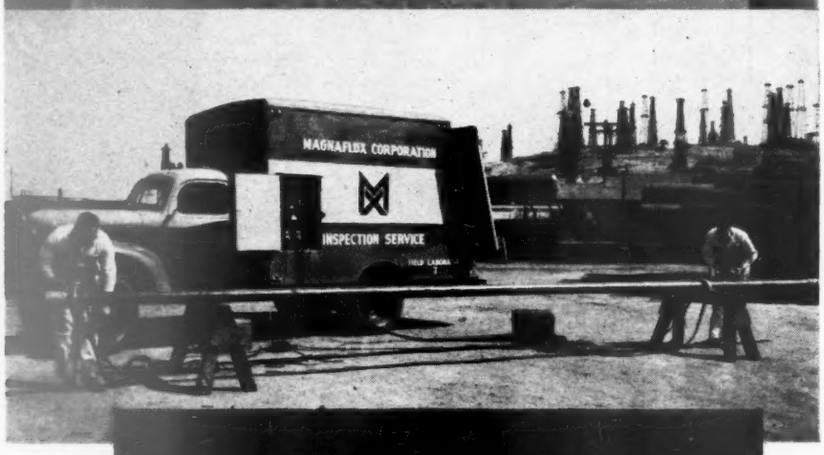

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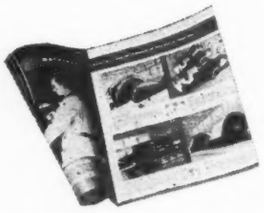

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In water-drive reservoirs, it is now possible through the same techniques employed in analyzing the water influx into a reservoir to take into account the effects of known structural or depositional features on the rate of water influx into a particular reservoir. The effects of a nearby fault, decreased formation permeability around a field, formation pinchout, and limitations of size of the water-bearing portion of a producing formation on the water drive of a reservoir can be quantitatively determined or predicted. The electrical analyzer is a particularly useful device in this connection. This again is a technical region in which both the engineer and geologist must cooperate to provide the quantitative basic information required for intelligent exploitation. The regional geology is as important an element in the problem as are the producing conditions in a reservoir itself.

● **Significance of quantitative technical observations.** The various examples cited for illustration in the preceding discussions are not unusual; problems are being solved regularly by equivalent approaches. Further developments now under way along various lines will bring accelerated progress as the solution of one problem points the way to the solution of another. The significance of this trend may be summarized as follows:

1. As it becomes more widely recognized that methods and knowledge are available that will supply quantitative results, management will demand such results and will reject qualitative substitutes.

2. To keep pace with the technological progress under way and to contribute his part to its further advancement, the technologist will be forced to sharpen his physical and mathematical intuition and his powers of perception.

Quantitative technology in oil production requires an exact comprehension of the chemistry, physics, and mechanics of the oil recovery process. In these sciences quantities are expressed precisely; their language is largely mathematics. A statement or observation that lacks precision is of little scientific value or use. Thus, those who by habit are prone to adopt the purely descriptive approach must adapt themselves to the more difficult task of quantitative study. Those unable to change pace to meet the accelerated tempo of the immediate future face the same technical obsolescence that has overtaken artisans of other industries when their skills based on sight, taste, smell, or feel were displaced by scientific controls based upon precise measurements.

The technical problems involved in oil production cannot be narrowly confined to any one branch of engineering or of science. The utmost skill of our engineers and geologists must be combined. It is to be hoped that the necessary cooperation will result from their common need of mutual support.

★ ★ ★

Reduction of Sulphates in Oil-Field Water*

By F. B. PLUMMER and I. W. WALLING†

● **Chemical reactions due to bacteria in salt water.** Bastin and others have demonstrated the presence of sulphate-reducing bacteria in oil-field waters and ascribed the presence of hydrogen sulphide in some cases to bacteria. In this paper the writers attempt to show quantitatively the effect of bacteria on sulphates in East Texas oil-field water and to demonstrate the environmental and chemical factors that control or affect bacterial activity.

East Texas salt water, when it comes from the oil sand, contains about 300 mgr. per liter of sulphates. After it has passed through the oil-field separators, tanks, and pits and is ready for disposal back into the ground, it contains about 250 mgr. per liter of sulphates. Therefore, about 70 mgr. per liter of sulphates have been reduced and converted into about 29 mgr. per liter of hydrogen sulphide. The reaction may be represented:

$$Na_2SO_4 + \text{bacteria} \longrightarrow Na_2S + 2O_2$$

$$2\,Na_2S + 2H_2O \longrightarrow H_2S + 2NaOH$$

The hydrogen sulphide then reacts with soluble iron in the water to form a black iron sulphide:

$$H_2S + Fe(HCO_3)_2 \longrightarrow FeS + 2H_2O + CO_2$$

This iron sulphide settles to the bottom of tanks and separates as a black sludge. If, however, there is much oxygen in the water or if the water is agitated so that oxygen from the air is mixed with the water, then the black sulphide is oxidized to flocculent reddish brown iron hydroxide, hydrogen sulphide, and sulphur.

$$2\,FeS + O_2 + 4H_2O \rightleftharpoons Fe(OH)_3 + H_2S + S$$

In most cases there is a mixture of iron sulphide and iron hydroxide, the proportions of which depend upon the oxygen content of the water.

These black and reddish-brown precipitates are a great nuisance in oil-field operations because they have to be cleaned out of tanks and treaters and filtered out of water to be returned to the oil sand; otherwise they will quickly clog the sand in an intake well. Hydrogen sulphide also causes corrosion of tanks.

● **Characteristics of sulphate reducing bacteria.** The sulphate reducing bacteria, *Vibrio thermodesulfuricans* (Elon), (Fig. 1) that thrive in salt water are very minute, anerobic, sausage-shaped cilliate organisms. They will not live in air or oxygen and develop best at comparatively high temperatures, 80 to 140° F. In the East Texas oil field the common treatment used to attempt to destroy sulphate-reducing bacteria is chlorine, generated either by electrolysis of salt water or by discharging chlorine into the water from liquid chlorine cylinders. Chlorine treatment of water is excellent for pathogenic bacteria like *Colon bacillus* but is not effective for sulphate-reducing bacteria. Sulphate-reducing bacteria are adapted to strong chloride solutions and a small dosage of chlorine in large volumes of water has little effect upon them. Chlorine, however, is a strong oxidizing agent, and chlorine treatment serves to help oxidize the ferrous compounds and change iron sulphide to the more flocculent ferric hydroxide. As chlorine does not kill sulphate bacteria, other means are needed to get rid of these obnoxious microorganisms. It has been found in the laboratory that it requires ten days to two weeks for sulphate-reducing bacteria to develop in sufficient quantity to produce harmful amounts of hydrogen sulphide. Therefore, it was thought that since water passes through the East Texas oil-field installations and is disposed of in 24 hr., that either the bacteria developed altogether in stagnant places in the salt water systems or else some factors other than bacteria were responsible for the formation of the hydrogen sulphide. Accordingly a series of investigations were undertaken to test these explanations.

● **Laboratory investigations of sulphate reduction by bacteria.** Water was collected from the wellhead in the East Texas oil field without allowing any air or contaminating substances to come in contact with it. The bottles were then placed in constant temperature incubators in the laboratory and allowed to stand for 30 days. The concentration of sulphate in the water was determined by standard analytical methods at the beginning of the experiment and repeated at the end of each 10-day interval until 30 days had elapsed. At the same time the amount of hydrogen sulphide produced was calculated, and the results plotted on graph paper. Results of experiments are summarized below.

● **Effect of temperature on sulphate reduction.** Bottles of water from the East Texas oil field were incubated for 30 days at temperatures of 60°F., 70°F., 80°F., 90°F., 125°F., and 150°F., respectively, and the amount of sulphate reduction and hydrogen sulphide formation determined as described above.

The results are shown in the graph, Fig. 2. It will be noted from these results that if the bacteria are removed by sterilization of the water that no reduction takes place. At 60°F. and at 70°F. very little reduction is noticed in unsterilized water. Largest reduction and most hydrogen sulphide formation takes place at 125°F. No reduction takes place at 150° F. Temperature is an important factor in reduction of sulphates by bacteria, and this effect explains why sulphate reduction in oil-field waters is more active in summer than in winter.

● **Effect of oil-field materials on sulphate reduction in East Texas oil-field water.** If one notices the enormous amount of black iron sulphide formed in oil-field salt water pits and contemplates how little sulphate reduction takes place, (amounting to less than 10 per cent) in the laboratory under optimum temperature conditions during an entire 30-day period, one is sure to conclude that some process other than bacteria must be operative in the oil fields. In order to investigate the effect of all other reducing substances other than bacteria, all possible substances with which water in the East Texas oil field comes in contact both together and separately were incubated along with and without bacteria for a 30-day period and the water analyzed at each 10-day interval for sulphate and hydrogen sulphide as before.

The results are shown in the graphs,

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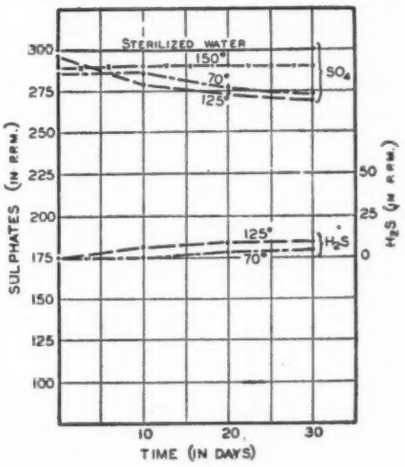
†University of Texas, Austin, Texas.

FIG. 1. *Vibrio desulfuricans* van Delden, sulphate-reducing bacterium found in water from oil wells, magnified about 4500 times. Photograph by H. J. Sawin.

FIG. 2. Graph showing effect of temperature on sulphate reduction in salt water from East Texas oil field.



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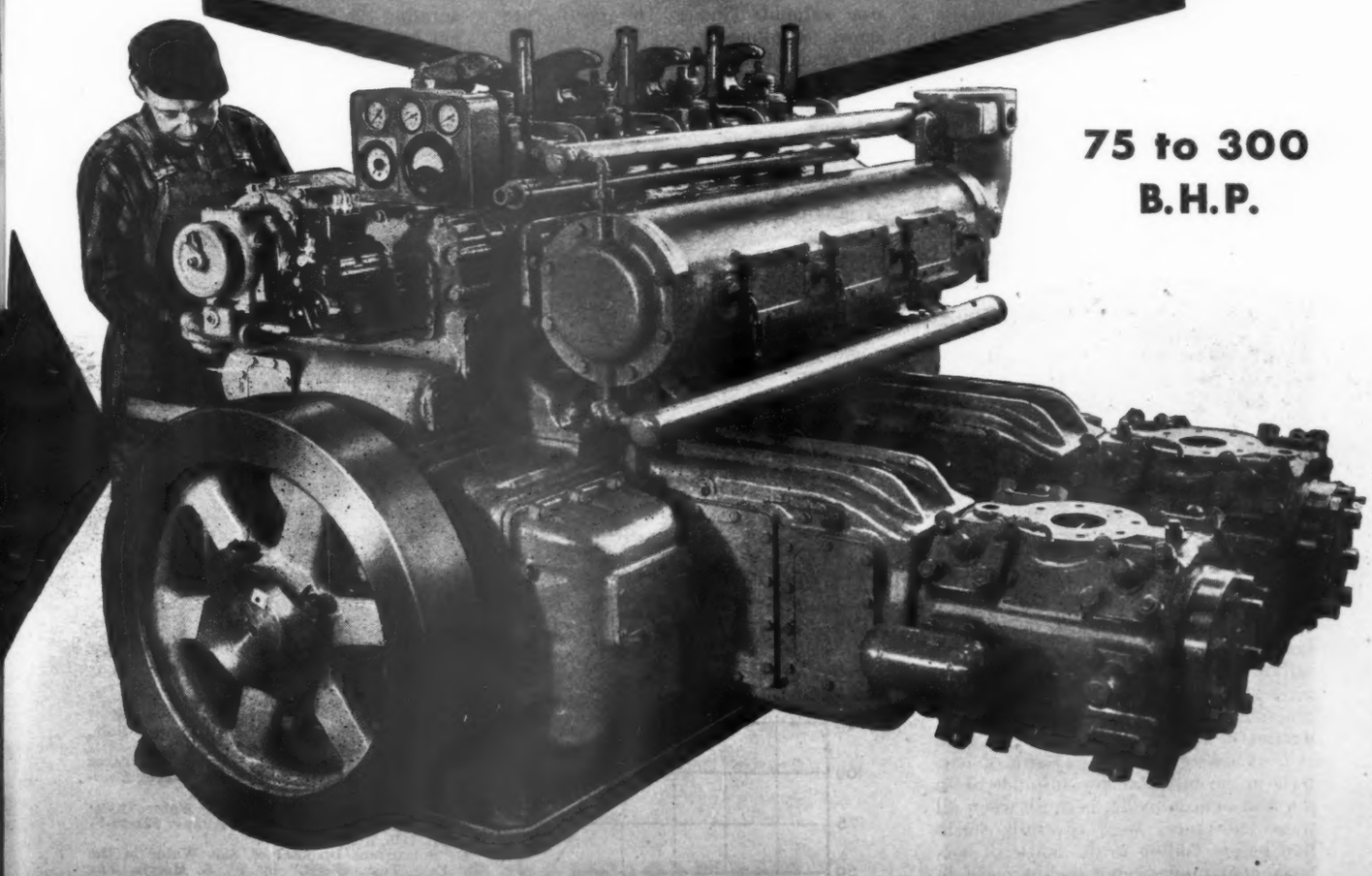

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FIG. 3. Effect of oilfield materials on sulphate reduction by bacteria.

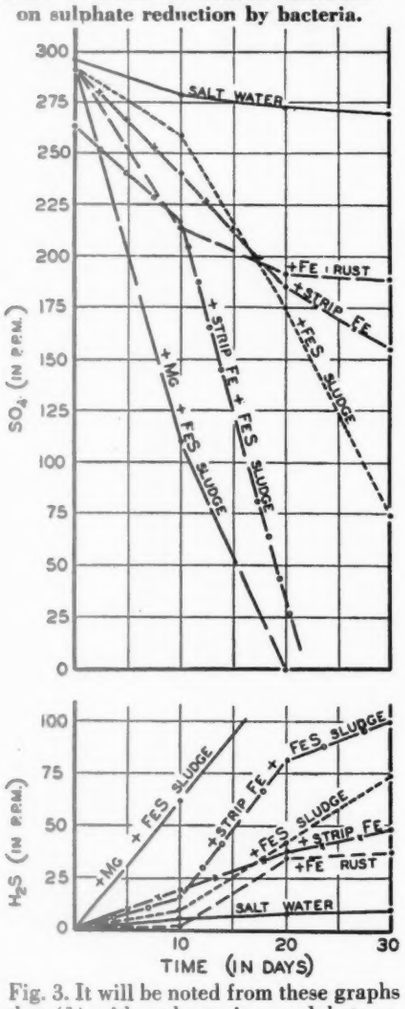


Fig. 3. It will be noted from these graphs that (1) without bacteria no sulphate reduction takes place, (2) the addition of colloidal iron sulphide sludge increases the amount of reduction of sulphate in water containing bacteria at the end of a 30-day period by 60 per cent, (3) iron rust, metallic iron and metallic magnesium also accelerate the reaction, (4) the combination of 3 ingredients, metallic iron, ferrous sulphide, and iron rust increases the reduction 90 per cent and (5) on the other hand, if the water is sterilized and the bacteria removed, no reduction takes place no matter how large a quantity of these metals and metallic compounds are added. Hence, bacteria are necessary to start the chemical reaction. Furthermore, the increased reduction of sulphate was not due to addition of a new and large swarm of bacteria in the colloidal iron sulphide or on the iron or iron oxide, because when all these substances were carefully sterilized before adding to the bottle of bacteria containing water the increase in reduction of sulphate was the same as when the materials were not sterilized.

● **Quantity of ferrous sulphide sludge required for reduction of sulphate in oil-field salt water.** In order to investigate the effect of different quantities of colloidal ferrous sulphide on the reduction of sulphates in East Texas oil field, water was incubated for 30 days with various amounts of ferrous sulphide sludge ranging from 10 ml. per 2½ liters to 150 ml. per 2½ liters of water. The results are shown graphically in Fig. 4. It is apparent from these results that the larger the amount of colloidal ferrous iron sulphide sludge added to the oil-field water the greater the sulphate reduction; however, amounts as low as 10 ml. per gal. increase the amount of reduction materially.

● **Effect of bactericides on the reduction of sulphates by bacteria.** Different common bactericides were added to the East Texas samples of salt water, the water placed in the incubator and incubated as before. The results are shown in Fig. 5. It was found that most of the bactericides tried, such as phenol, formaldehyde, cresol, lysol, and creosote, except alcohol and chlorine, killed the bacteria and prevented sulphate reduction.

● **Amount of bactericides required to kill bacteria in salt water.** Finally experiments were carried out by the same method described above to find out the minimum quantity of bactericide required to treat 2½ liters of water containing bacteria and 25 ml. of colloidal iron sulphide sludge. The results are shown as follows:

Formaldehyde	0.1 ml.
Cresol	0.1 ml.
Phenol	2.5 gm
Lysol	2.5 ml.
Monochlorbutene . . .	3.0 ml.
Trichlorbutane	3.0 ml.
Creosote	7.5 ml.

● **Conclusions.** Reduction of sulphates in oil-field waters may be prevented or at least greatly reduced as follows: (1) By cooling the water to below 70°F., (2) by using non-iron equipment, such as concrete or wooden tanks in place of iron, or if iron tanks are used by coating

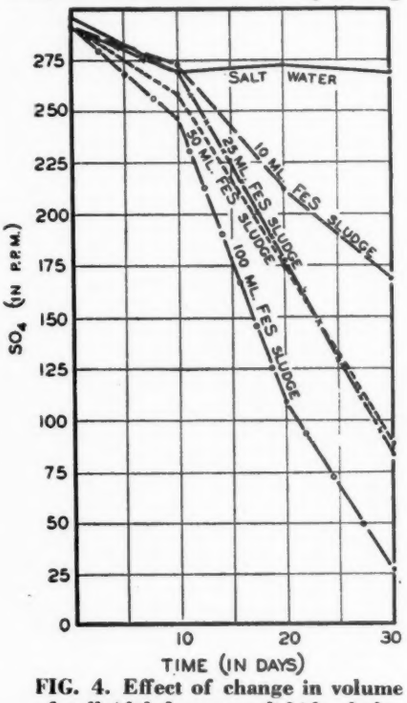
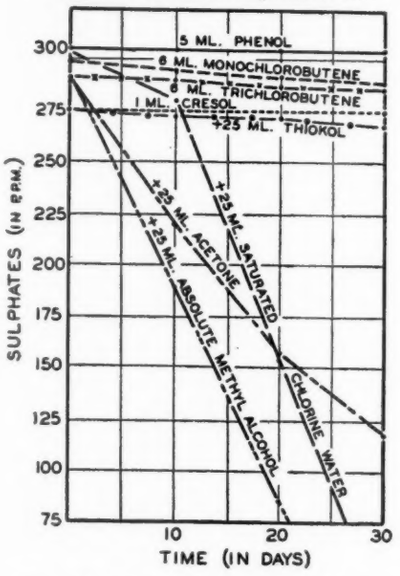


FIG. 4. Effect of change in volume of colloidal ferrous sulphide sludge on sulphate reduction.

FIG. 5. Effect of bactericides on sulphate reduction by bacteria.



the inside of the tanks with rubber or plastic compound so that water does not come in contact with the iron, (3) by aerating the water (this method should not be used if iron tanks are employed, for aeration causes corrosion), and (4) by using bactericides. The killing of the sulphate-reducing bacteria by bactericides or heat treatment not only prevents the formation of black and brown troublesome sludges, but also prevents the formation of hydrogen sulphide, and therefore, reduces much corrosion of the inside of oil-field tanks where the corrosion is due to hydrogen sulphide.

● **Acknowledgments.** These laboratory investigations have been made possible by research grants from East Texas Salt Water Disposal Company and National Tank Company. Grateful acknowledgment is due assistance of A. W. Francis of the National Tank Company and W. S. Morris, L. H. Dial, and A. R. Scharnagel of the East Texas Salt Water Disposal Company. The investigations were carried out in the research laboratories of The University of Texas, with the active cooperation of Harry H. Power of the Petroleum Engineering Department, Raymond Dawson of the Bureau of Engineering Research, and Dr. J. T. Lonsdale of the Bureau of Economic Geology. P. A. Witt assisted in laboratory work.

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Application of Petroleum Engineering to Drilling and Production Work*

By **BOWMAN THOMAS,** Humble Oil and Refining Company

● **Introduction.** The purpose of this talk is to present some of the applications of petroleum engineering to drilling and production work and the probable trend of petroleum engineering in the future. Before presenting specific applications of petroleum engineering, some general information on the petroleum industry might be of interest.

The petroleum industry in the United States is one of the largest and ranks with railroads and public utilities in importance to the national economy. The petroleum industry will continue to be one of the most important industries in the United States, certainly for many years to come. Oil and gas supplied 44 per cent of the United States' energy-source in 1940, compared with 50 per cent for coal and 6 per cent for water power. The United States supplies approximately 65 per cent of the world's crude-oil production and has approximately 40 per cent of the world's known reserves. The investment in the United States' petroleum industry is probably between 18 and 20 billion dollars, and nearly one-half of this investment is in producing properties. Approximately 17 per cent of the employes in the petroleum industry are in the production branch. The petroleum industry is one of the highest paid, with an average for wage earners of approximately $1.40 per hr. at the present time. Average weekly earnings are approximately $56.

Before citing the many applications of petroleum engineering to drilling and production work, the position of the petroleum engineer in an oil-producing organization should first be explained. The petroleum engineer is a service or advisory employe, the same as the lawyer and the industrial relations man. He justifies his existence by rendering a useful service to both management and labor. For management, he analyzes operations and develops plans for operations. For labor, he endeavors to develop equipment and methods to make work easier and safer. He strives to reduce costs to make the future of his company, and labor's jobs, more secure. Of course, in helping others, he automatically improves his own lot, but helping others must come first.

The applications of petroleum engineering vary from one company to another. Discussed below are some of the applications.

● **Drilling.** Drilling equipment and methods are a very interesting phase of petroleum engineering. In drilling operations, each day presents new problems and decisions that must be made. Because all of you are interested in the future of petroleum engineering, some of the current problems and possible future applications of petroleum engineering in drilling will be pointed out.

The pressing need for the application of petroleum engineering is in the field of reducing drilling costs. Drilling costs have increased at an alarming rate over the last ten years. The cost of wells has increased at least fourfold. Wells costing more than a half-million dollars each and more than $50 per ft. are not uncommon. This alarming increase in well costs does not, however, mean that petroleum engineers have been asleep on the job. Much of this increase in well costs is the result of petroleum engineers and others making possible the drilling of deeper wells and opening new zones for drilling that could not be drilled before because of various obstacles. For example, 15 years ago many wells were not drilled to the scheduled depth because of stuck drill pipe—in coastal regions the hazard was greater below approximately 6000 ft. The petroleum engineers have since eliminated most of the causes of stuck drill pipe, thus opening the field for drilling to 15,000 ft. and more in the coastal regions; but the solutions have been difficult and the cost has been high. For example, for the true *heaving shale* conditions, it is now necessary to use a drilling mud costing approximately $12 per bbl. or $12,000 to fill the circulating system. An additional cost of $200 per day is often required to keep this mud in condition. The present application of petroleum engineering is to develop cheaper ways to control heaving shale.

Another cause of stuck drill pipe is *high-filtration muds* in which the water from the mud filters into permeable formations and causes the accumulation on the walls of the hole of a thick filter cake that sometimes reduces the size of the hole to the extent that the drill pipe cannot be removed. Special drilling muds, known as alkaline-tannate muds and starch muds, have been developed to reduce the thickness of the filter cake, and cost approximately $0.25 to $1.00 per bbl. and $35 to $125 per day to keep in condition. Again, it is today's application of petroleum engineering to find a cheaper way of doing this job. By cheaper, of course, is meant a cheaper overall way of doing the job, not merely the adoption of cheaper mud-treating chemicals.

Hole enlargement has been another cause of stuck drill pipe, which has barred the way to drilling of deeper wells. By hole enlargement is meant continual enlargement of the hole because of sloughing as drilling progresses. Sometimes the sloughing of the hole walls has not been the immediate cause of stuck drill pipe, as in the case of true heaving shale conditions, but the gradual enlargement of the hole has caused a corresponding reduction in the linear velocity of the returning mud fluid, to the extent that cuttings will settle back and accumulate at various points in the hole and slough into the hole causing stuck drill pipe. The application of low filtration, alkaline-tannate or starch mud has helped to check this condition by reducing the rate at which water is absorbed by the formations from the drilling mud. Increasing the rate of circulation and endeavoring to maintain a maximum drilling rate has also helped to combat the hole-enlargement condition because hole enlargement is proportional to the time spent drilling.

The aforementioned hole-enlargement condition has been one of the bars to wider use of so-called slim-hole drilling, at least in the coastal regions. Slim-hole drilling was proposed as one means of reducing drilling costs; that is, by the use of smaller diameter hole, smaller diameter drill pipe, and smaller drilling rig, it was hoped that drilling costs could be reduced. However, it was found that even though a 6¾-in. bit was used to drill the hole, many points in the hole enlarged to 20 in. or more with the result that the small-diameter drill pipe and small-sized pumps could not provide sufficient circulation to carry out the cuttings and to prevent stuck drill pipe. There was also a greater tendency for the smaller diameter hole to drill crooked, probably because of the inability to provide adequate drill collar weight on bottom in the limited sized hole. The small-diameter drill collars used in slim-hole drilling also experienced more joint failures and fishing jobs, which were a deterrent to reducing drilling costs. The trend now is toward even larger diameter drill pipe than the conventional 4½-in. in order to provide adequate circulation at greater depths. The purpose of the larger diameter drill pipe is to reduce the greatly increased *pressure loss through drill pipe*, resulting from: (1) longer strings to pump through (15,000 ft. instead of 6000 ft. 15 years ago), and (2) increased viscosities that accompany heavier weight and special drilling muds necessary to cope with higher formation pressures and other formation conditions. There is nothing new in the use of larger diameter drill pipe and nothing would be gained if the hole size were increased correspondingly to accommodate the larger drill pipe because more circulation through the drill pipe would be required to provide the necessary mud-return velocities to remove cuttings. The appli-

*Presented before the petroleum engineering students, University of Oklahoma, Norman, February 26, 1946.

cation of petroleum engineering in this case is to provide a drill pipe having less pressure-loss yet requiring no larger diameter hole to accommodate it, such as the new 5-in. O.D. drill pipe that has the same 6¼-in. O.D. tool joint as the conventional 4½-in. internal flush drill pipe, but has approximately 25 per cent less pressure-loss through the inside. Reduced pressure loss through drill pipe results in less slush-pump size, weight, and investment; less slush-pump piston, valve, and packing failures; less slush-pump downtime and consequently, the ultimate goal before the petroleum engineer—reduced drilling costs.

The *hydraulics of the rotary drilling system* is an important field for the application of petroleum engineering. A number of field tests have indicated that the drilling rate is roughly proportional to the rate of fluid circulation in any given sized hole, at least in the Gulf Coast area where formations are less consolidated. This relationship offers a promising field for reducing drilling costs. Under some conditions there is a limit to the rate at which drilling mud circulation can be increased without lost returns resulting. Increased rate of circulation causes an increase in bottom-hole pressure as a result of the increased friction loss of the returning drilling fluid and thereby results in *loss returns* if there is only a small margin between the bottom-hole mud-pressure required to offset formation pressures and that at which lost returns will occur. This small margin is a serious problem in deep drilling in the coastal regions and the solution has not been found. Many expensive wells have been abandoned below a depth of 10,000 ft. because a mud weight ample to combat abnormal formation pressures was also heavy enough to cause lost returns which permitted the fluid head in the well to be reduced and the formation pressures to get out of control. This condition has arisen in wells where the upper formations that usually cause lost returns with heavy mud weights have been cased off with a protection string of 10,000 ft. or more, which is set as a regular procedure when abnormal formation pressures and heavy mud weights are anticipated.

By abnormal formation pressure is meant formation pressure in excess of 0.465 lb. per ft. of depth. Recently a well was abandoned in South Louisiana having a formation pressure nearly twice this amount, 9373 lb. at a depth of 10,300 ft. The mud weight was 18 lb. per gal., more than twice the weight of water.

The lost return problem as outlined above, is one of the most serious problems confronting the petroleum engineer at the present time. The usual remedies in the way of using fibrous material in the mud to seal permeable formations are of no avail under these conditions. The use of cement, which is sometimes effective in sealing crevices and caverns that cause lost returns, is also of no avail under the conditions set out above. The practice of drilling with water without returns, when formations causing lost returns cannot be sealed, is also of no avail under the conditions described above because the weight of water is not great enough to offset abnormal formation pressures.

It is apparent that the rotary drilling system has inherent weaknesses, as exemplified in the lost return problem, and the petroleum engineer should certainly give consideration to developing an entirely new and better system for drilling as well as endeavoring to refine the present rotary drilling system. It is apparent that the applications of petroleum engineering are increasing rapidly rather than decreasing. The petroleum engineer is getting problems faster than he can solve them, at least without increased costs. Drilling costs are increasing rapidly because of more hard formations to drill; abnormal pressures to contend with; more wildcats to drill which are inherently more expensive; much deeper wells; higher costs for labor, transportation, and material; and more edge wells and difficult completions. The petroleum engineer is not developing means of reducing costs as fast as these factors are contributing to higher drilling costs. He seems to be doing well to meet the daily problems of getting the jobs done. The future also does not hold any possibility for fewer problems or less work for the petroleum engineer. There is talk of off-shore drilling in open ocean in water depths of 100 ft. and more, and the cost of anything in connection with marine operations, particularly in this unexplored

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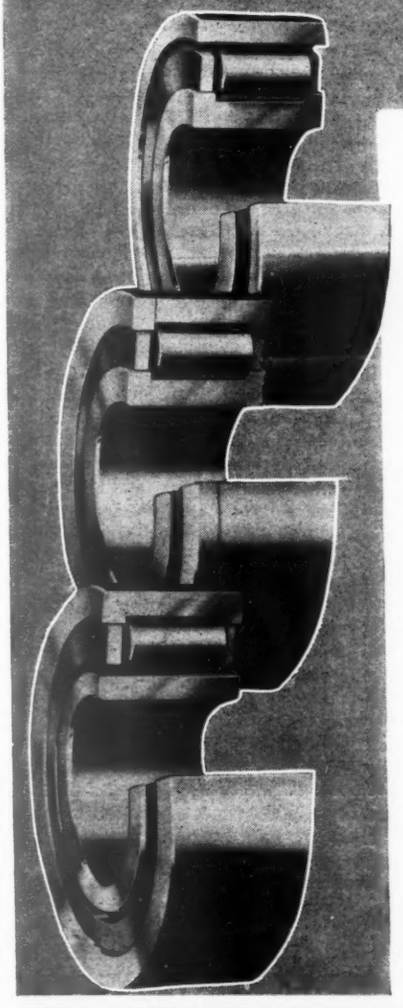

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field of endeavor, is going to be high and possibly prohibitive unless significant technical improvements can be made. The trend of increased well costs without developing any more oil per well cannot continue indefinitely without adversely affecting the economics of the industry and of the consuming public.

Turning now from the darker side of the picture, some of the past achievements of the petroleum engineers will be presented to give more specific examples of the applications of petroleum engineering. Again, as mentioned in the beginning of this paper, the petroleum engineer has not made all these achievements by himself and he will not make future achievements without the wholehearted cooperation of all his co-workers. Many of the achievements listed below have been the result of equipment manufacturers' contributions. However, the petroleum engineer contributed to these achievements by calling to the manufacturers' attention the need for improvement and the problems involved, and by assisting the manufacturer in the application and care of improved equipment. Some of the noteworthy achievements that petroleum engineers have contributed to during the past 17 years are as follows:

Increased bit footage. Fishtail bit footage under the same drilling conditions has increased from approximately 50 ft. to 1000 ft. per bit over the past 17 years. This improvement has to a great extent been the result of the application of hard metals to the cutting surfaces, the use of better steels that resist bending and breaking off, better location and size of water courses for cleaning and cooling the bit, and the use of hard metal slush tubes for keeping the water courses to size. In the early days of these improvements, fishtail bits were usually dressed in the operator's field shops under the supervision of his petroleum engineer. The improvements resulted from careful study of worn bits and the trial of various steels and many different kinds and arrangements of hard metal applications. The reaming edge of the bit required considerable attention in order to hold the bit to gauge in service. The thickness and shape of the cutting blades were important factors in maintaining a sharp cutting edge as long as possible. Improvement of rock bit performance has been obtained by the trial of different types of bits furnished by the manufacturer and by carefully recording the results obtained with the different types of bits. The performance data, which the petroleum engineer obtains, is invaluable to a manufacturer in developing a better product. The importance of the rotary bit cannot be overemphasized because the performance of the entire drilling rig and, consequently, cost of drilling wells is greatly influenced by the performance of bits.

Drill pipe. Drill pipe has always been an expensive item to the operator. The life of drill pipe has been increased greatly through the combined efforts of the petroleum engineer and the manufacturer. The petroleum engineer kept records of the performance of drill pipe and the nature of failures. It was found that most of the failures were occurring at the last engaged thread of the threaded joint between the tool joint and the drill pipe. These failures were eliminated by redesigning the joint. The petroleum engineer recognized the need for a larger opening through drill pipe, which in the early days was greatly restricted at the tool joint and as a result, the internal flush-joint was developed which resulted in greatly reduced pressure loss through drill pipe. It was then noted that tool joint wear was excessive on the outside diameter of the tool joint and hard surfacing was applied to resist wear. Difficulties have been experienced with galling of tool joints and drill collar joints, and with joint breakage. These have called for changes in the design of joints, better threads, better thread lubricant, and better care in the field. The combined efforts of the petroleum engineer, the operator, and the manufacturer have resulted in worthwhile savings when it is taken into account that such failures usually result in expensive fishing jobs. Also drill pipe and tool joints in themselves are expensive items.

Blowout hazards. The possibility of a blowout and wild well is always a threat to the loss of a well and drilling rig, and possible damage to a valuable oil and gas reserve. Although considerable improvements have been made, the problems in this field certainly have not been solved because blowouts still occur and there is a broad field for the petroleum engineer, (1) to see that blowouts do not occur, (2) make certain that adequate wellhead control equipment is in service, and (3) to develop procedure and equipment for combating blowouts, should they get out of hand.

Casing and tubing. Considerable economies have been effected by the application of engineering to casing and tubing strings. Stronger and more leak-resistant joints have been developed. Casing strings are now designed for the specific job by providing only the necessary collapse, burst, and tensile strength for various depths in the hole, as compared with the old method of designing the entire string for the maximum condition at some point in the hole. The present method, which consists of selecting the proper material, wall thickness, and joint for the maximum conditions at a particular depth in the well, effects economies of approximately $3000 or more per well for wells 10,000 ft. and deeper. The design of these strings is an engineering job.

Standardization of drilling rig layout. Considerable savings in transportation, setting-up, and tearing-down of drilling rigs has been effected by careful planning of the entire drilling-rig layout so that no major piece of equipment must be handled more than once in the moving operation. Each piece of equipment goes into the same place and is connected with prefabricated piping and manifolds as rapidly as possible with quick connecting unions. By careful planning of over-all moving and setting-up operations, savings of more than $1500 per well have been effected.

Size relation of drilling equipment. The proper relation between the size and capacity of the various items of drilling equipment is a subject requiring constant study to meet varying drilling conditions; and considerable economies in reduced rig investment and improved rig performance have resulted. Each piece of drilling equipment should be no larger or heavier than necessary because of the higher investment and transportation cost involved in the use of the larger equipment, but it shoud be large enough for maximum functioning of the other items of drilling equipment. A proper balance must be maintained between the hoisting capacity, size of piping, hose, swivel, drill pipe, and bit water courses, and the hole size and projected well depth.

Well logging methods. Many devices and services have been developed to improve the logging of wells; that is. the determination of the kind of formations drilled, the nature of their fluid content, and their productivity. Such developments are electric logging, gamma ray logging, caliper surveys, formation sampling, and drill-stem testing. These services have contributed greatly to identifying formations and to finding oil, and have become useful tools for the geologist and engineer; however, not one of these methods, or a combination of them, provides positive identification of formations or evaluation of their oil and gas producing ability. It is felt that most of these logging techniques are in the early stages of development and it is believed that this is a field for petroleum engineers to make needed improvements.

Directional drilling. Directional drilling is a specialized engineering service which has been satisfactorily developed. While most directional drilling is planned and executed with a minimum of difficulty and with good results, there are some applications for which the service can be improved, such as the deviation of holes through steeply dipping hard formations.

Drilling time studies. Drilling time studies have resulted in appreciable savings in drilling costs by pointing to savings that can be effected in drilling time. Drilling time and costs are roughly proportional. The petroleum engineer keeps detailed records on each well of time spent on rig moving, drilling, coring, casing and cementing, completing, rig repairs, conditioning mud, deviation tests, fishing, formation logging, drillstem testing, waiting, abandoning, and other phases of well operations. Such records reveal excessive downtime that should be eliminated. Every day saved with a company rig will reduce the well cost approximately $800, the exact amount of saving depending on the size and type of rig. In many fields drilling time and costs have been reduced as much as 50 per cent through careful analysis of drilling time and a concerted effort of all concerned to reduce it. At the present time, an effort is being made to have the

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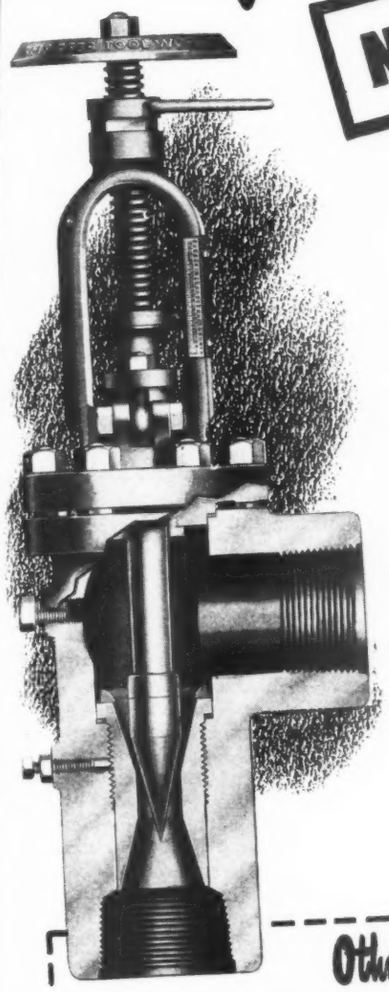
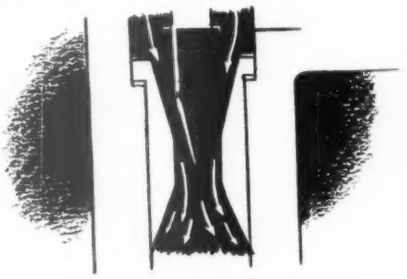


ONE adjustable flow bean may look like another . . . but don't be fooled. The spot where the work is done is in the orifice . . . and here's where Shaffer—the organization that *pioneered* adjustable flow beans—has engineered extra performance and higher flow efficiency into Shaffer Adjustable Flow Beans. Notice how the orifice tapers at *both* the entrance and discharge sides. This important feature permits the fluid to flow through the orifice with less turbulence and emulsification. Here's why:



IN THE SHAFFER FLOW BEAN the fluid is guided into the orifice by the tapered inlet . . . then on the discharge side is guided out again by the tapered outlet. This controls the fluid flow, bringing it gradually to the full diameter of the discharge pipe, *without the turbulence and emulsification caused by a straight orifice tube.*

IN ORDINARY FLOW BEANS the discharge side is a straight tube without the taper characteristics of Shaffer Flow Beans. Fluid emerging from this straight bore is not controlled as it flows into the discharge line. This uncontrolled flow causes eddy currents, increases flow turbulence, and tends to emulsify the fluid.

This Shaffer advantage is important. Less emulsification means less treating costs for separating water from the oil . . . and greater handling efficiency in your production and refining operations. And here's another advantage . . . the Shaffer Adjustable Flow Bean may be connected in the hook-up so that the flow is either toward or against the tip —an advantage that is not practical with the straight discharge type of orifice. This feature greatly facilitates hook-ups, and permits wider versatility in installing Shaffer Flow Beans than with conventional types.

Other Shaffer Features...

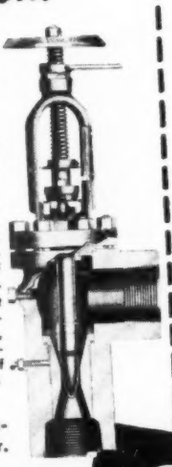
THERMO TIP

And here's a unique Shaffer development that is a big help in handling waxy fluids—or where rapid expansion of gas in the crude oil causes ice to form at the orifice. It's a tip which incorporates an electrically heated element that heats the fluid as it passes through the orifice, thus preventing ice from forming or wax from clogging the orifice and choking the fluid flow. The unit operates from any standard 110-volt circuit, and the tip in the 2" size is heated to about 850° F. under atmospheric conditions. On larger sizes greater heat can be obtained if desired.

MICRO TIP

Often it is desired to secure an equal increase in opening area for each turn or fractional turn of the adjusting screw throughout the entire travel of the tip. You get this feature in the Shaffer Micro Tip with which any Shaffer Flow Bean can be furnished.

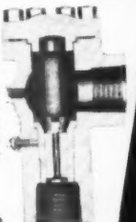
The advantage of this tip is that very small openings can be secured with great accuracy—and the increase or decrease in the size of the opening will be absolutely uniform throughout the entire travel of the adjusting screw. In addition, this tip provides a flow pattern that duplicates that of an almost perfect venturi tube.



Also where sand is a problem, special abrasion-resisting tips are available to minimize wear.

INTERCHANGEABLE POSITIVE CHOKE

Here's a way to cut hook-up costs. Use the Shaffer Adjustable Flow Bean to determine the proper size orifice for pro-ration purposes. With this determined, the yoke, stem and tip can then be replaced with an insert and fixed choke having the proper size hole. A blanking off cap is substituted for the yoke—and you have a positive fixed-diameter choke, while the yoke, stem and adjustable tip are salvageable for other applications.



For helpful information on Shaffer equipment, see Pages 2687 to 2730 of your Composite Catalog.

FLANGED OR THREADED CONNECTIONS... WIDE RANGE OF SIZES

There is a Shaffer Adjustable Flow Bean to fit every requirement . . . whether flanged or threaded connections . . . bolted or threaded yokes . . . and in sizes from 1" to 6" pipe. Pressure test ratings up to 10,000 lbs. per square inch. See your Shaffer representative for complete information on these Flow Beans . . . or write direct!

Send for complete Shaffer Catalog.

SHAFFER

HIGH PRESSURE DRILLING AND CONTROL EQUIPMENT • FISHING TOOLS THAT EXCEL

SHAFFER TOOL WORKS, Brea, Calif. • California Service Shops: Santa Fe Springs and Taft • HOUSTON, TEXAS, 6006 Navigation Blvd. • ODESSA, TEXAS, 1925 W. 2nd St. • OKLAHOMA CITY, OKLA., Acme Oil Tool Co., 1001 S. E. 29th St. • EXPORT SALES OFFICE: Shaffer Tool Works, 30 Rockefeller Plaza, New York, N. Y., U. S. A.

present rules requiring a waiting time on casing cement of 48 to 72 hr. changed to 24 hr. or less. Field and laboratory tests on the setting time and characteristics of cement reveal that a waiting time of 24 hr. is more than ample.

Oil well cements. Increased well depths and higher setting temperature for cements have resulted in the development of cements with longer setting time characteristics under high temperature conditions to allow ample time for placement of the cement. Present applications of oil-well cement reveal a need for a cement that is more readily penetrated with a gun perforator, cement that is less permeable and more resistant to attack by oil-well acids, and most significant of all, a cement, or cementing technique, that will provide a better seal between the well casing and the wall of the hole. Many expensive workover jobs are the result of the inability to effect this seal with the initial cement job. Plastics, which are now being tried in place of conventional oil well cement, give promise of being considerably better for this application.

Water treating. Provision of suitable water for boiling and engine cooling service is the petroleum engineer's job. The life of drilling boilers has been extended from approximately 5 years to more than 10 years by giving careful attention to providing suitable water for boilers, by providing proper maintenance and care, and by applying suitable treatments for water where treatment is necessary. The life of engines has been increased greatly by use of distilled cooling water in combination with a rust preventer, in areas where a suitable raw water is not obtainable.

Fuel. Fuel costs for drilling vary widely in different areas. When drilling a well in a new area, the overall cost of furnishing different types of fuel to the drilling rig must be computed in order to arrive at the most economical fuel. The overall cost must include the cost of all facilities for handling the fuel, such as pipe lines for transporting gas fuel; facilities for transporting, handling, and storing oil fuel, gasoline, and butane; and transmission lines and transformer installations for electric power. After the most economical fuel is selected, the next step is to determine the cost of obtaining a suitable power plant for that particular type of fuel, and next, the water suitable for that type of power plant. The type fuel and the type power plant used and the availability of suitable water have an appreciable effect on the overall drilling cost.

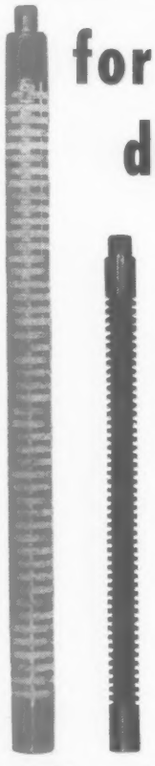
Drilling rig power plants. The selection of the size and type of power plants for drilling rigs is an engineering job of considerable magnitude. All factors, such as rig performance, downtime, and costs of depreciation, maintenance, transportation, fuel, water, and supervision, must be carefully evaluated in order to determine the most economical size and type of power plant for any particular area or drilling condition.

Communication systems. Although communication systems are usually not the direct responsibility of petroleum engineers, nevertheless it is the petroleum engineer's job to propose any means of reducing drilling costs. The installation of frequency modulated two-way radio equipment in remote areas where other means of communication are not available has effected considerable savings in drilling costs. It is in the interest of employe safety and welfare, as well as good business, to provide a rapid means of communication between isolated drilling sites and the operating headquarters. In emergencies aid can be dispatched by radio to the drilling site promptly, rig downtime can be reduced, and supervisor's time and transportation costs can be saved.

Drilling rig controls. There is still entirely too much manual effort required in the operation of drilling rigs. Petroleum engineers should endeavor to develop easier means of operating drilling equipment so that the skill and experience of drilling crews can be utilized in planning drilling work, anticipating well trouble, and concentrating on increasing the over-all efficiency of their operations rather than using their energy in tiring manual operation of drilling equipment. The application of electricity, hydraulic, and air-operated equipment has eliminated some of these tiring operations, and there is room for much more improvement.

● **Production.** Production operations, although not as spectacular as drilling, are nevertheless important because the

WHAT LENGTH MARTIN PLUNGERS for your particular well depth and conditions



The pumping load or pressure is divided evenly among all the Rings on a properly installed Martin Plunger; therefore, enough Rings must be used to keep the "pressure drop per Ring" low enough to give long wearing life.

In **very hard pumping conditions** use up to 2 Rings per hundred feet of fluid lift or well depth. •

In **average pumping conditions** use up to 1½ Rings per hundred feet of lift or well depth.

With small Martin Plungers (1", $1\frac{1}{16}$" and 1¼"), using 3 Ply Rings, add 50% more Rings.

Avoid Side Pull due to crooked holes or other causes—by using Rod Guide above working barrel or Rod Pump.

JOHN N. MARTIN
Manufacturer
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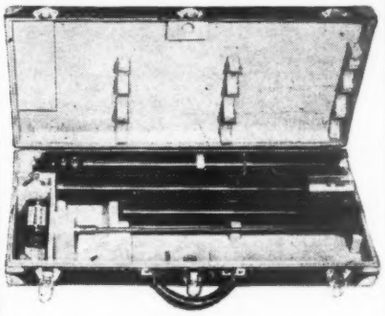

Makes a continuous record in one run of the direction of the hole and its deviation from the vertical. The complete survey is plotted in our offices and a finished copy supplied to the customer. For accurate, dependable surveys, call the *Pioneers* of oil well survey service.

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WISCONSIN-POWERED BOOSTER PUMP

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The unit illustrated above, built by Harley Sales Co., and operating in the service of a major pipe line company near Wichita Falls, Texas, operates a low pressure rotary pump, boosting 120 barrels of oil per hour at 40 lb. pressure. Dependable, heavy-duty power is supplied by a model AHH (8.5 hp.) single cylinder 4-cycle Wisconsin Air-Cooled Engine, equipped with clutch reduction assembly, direct-connected to the pump.

Wisconsin Air-Cooled Engines are giving good accounts of themselves on a great variety of service applications in the oil field at minimum upkeep cost and maximum engine-hour performance.

WISCONSIN MOTOR Corporation

MILWAUKEE 14, WISCONSIN

World's Largest Builders of Heavy Duty Air Cooled Engines

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Oil field distributors for Wisconsin Engines and all types of utility units.

production of petroleum and the marketing of products provide the source of income. The main phases of production operations are as follows:

Reservoir engineering. This is an important application of petroleum engineering in the production of oil. Reservoir engineering is the application of engineering principles to determine the physical characteristics of an oil and gas reservoir, the fluids therein, and the probable movement of fluids under well producing conditions. The physical characteristics include the dimensions of the reservoir, porosity, permeability, connate water and oil content, characteristics of the reservoir fluids under reservoir pressure and temperature, shrinkage of liquids on movement from reservoir to stock tank, and the type of drive propelling the reservoir fluids to the well bore—that is, water drive, dissolved-gas drive, or gas-cap drive.

Early recognition of the type of drive under which a reservoir is producing is essential in order to plan a development program that will result in maximum recovery at a reasonable cost. Conservation of the original reservoir energy, in the form of gas and water pressure, is a prime objective and the type of well completion determines the extent to which reservoir energy will be conserved and utilized. For this reason, the type of drive must be recognized as early as possible in the life of a new field so that the proper well completions can be made. For example, if a reservoir has only a dissolved-gas or gas-cap drive, then the well should be completed to produce from the lower part of the reservoir, thus deferring as long as possible free-gas production resulting from gas-cap expansion. On the other hand, if the reservoir is produced by a strong water drive only, then production usually should be obtained from the upper part of the reservoir so that a maximum yield of oil will be obtained before water production sets in. In actual practice, however, the applications of accepted principles of reservoir engineering are not this simple because of the complex nature of most oil and gas reservoirs; that is, irregularities in porosity and permeability, the presence of impermeable shale beds within the producing reservoir that are barriers to vertical migration of fluids, lensed sand conditions, and faulted conditions. A complete geologic picture is essential to proper evaluation of reservoir conditions, in addition to analyses of reservoir pressures, temperatures, formation samples, bottom-hole-fluid samples, productivity tests on wells, and reliable statistics on oil, gas, and water production by reservoirs.

The rewards, however, for reservoir engineering effort are great because only a small improvement of two to five percent in recovery may result in savings amounting to as much as a million barrels of oil. The same percentage of improvement in other operations is not nearly so profitable.

Reservoir studies make possible much more accurate predictions on future artificial-lift requirements and frequently are the means of deferring the need for artificial-lift equipment by prolonging the flowing life of wells by maximum utilization of reservoir energies for lifting the well fluids.

Reservoir engineering, in the early stages of the development of a reservoir, also saves many expensive workover jobs to shut off excessive water or free-gas production by early recognition of the type of drive and the proper kind of well completion to make.

One of the most useful applications of reservoir engineering during the war was the early determination of the maximum rate at which reservoirs could be produced without damage to the reservoirs and loss of recoverable oil. The maximum efficient rates were estimated for each field during the early stages of the war when production rates were low and these maximum rates later were found to be substantially correct after production rates were greatly increased. In a few cases, reservoir pressures declined and gas-oil ratios increased more rapidly than anticipated and in a few cases, observation under higher rates of production revealed that certain reservoirs could produce at even higher rates than originally estimated; but on the whole, the original estimates of maximum efficient rates were accurate, which is a tribute to the present stage of the science of reservoir engineering. Reservoir engineering, in the sense of close

Republic National Bank *of* Dallas

Statement of Condition June 29, 1946

RESOURCES

Loans and Discounts		$132,089,423.09
Banking House		1,930,999.31
Furniture and Fixtures		280,803.49
Real Estate for Bank Expansion		489,503.87
Stock in Federal Reserve Bank		600,000.00
U. S. Government Securities		68,076,249.40
Other Bonds and Securities		212,746.31
Cash and Due from Banks		76,830,700.40
Total		$280,510,425.87

LIABILITIES

Capital	$ 10,000,000.00	
Surplus	10,000,000.00	$ 20,000,000.00
Undivided Profits		2,001,915.43
Reserve for Dividend, Payable July 1, 1946		200,000.00
Reserve for Taxes, Etc.		1,746,891.36
DEPOSITS:		
Individual	$139,017,238.49	
Banks	84,066,548.18	
U. S. Government	33,477,832.41	256,561,619.08
Total		$280,510,425.87

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Completely Mechanical

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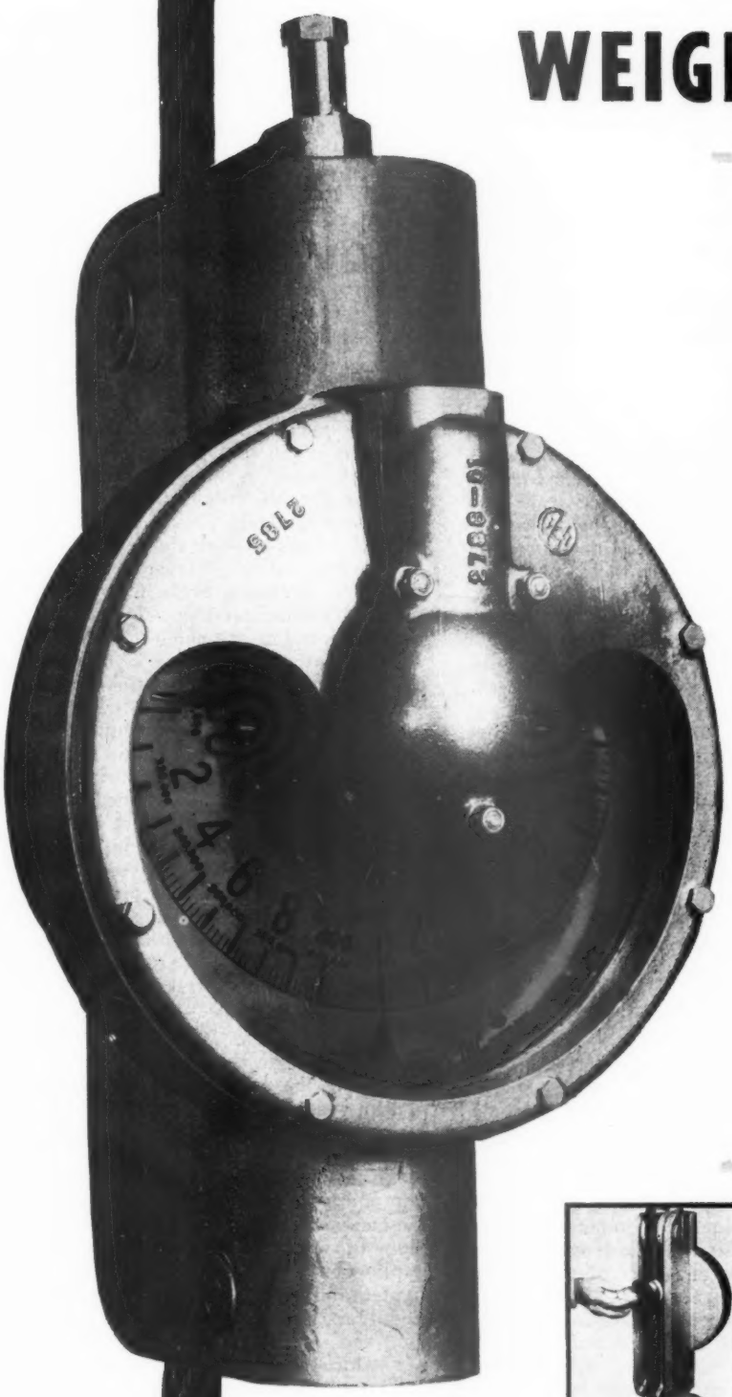
WEIGHT INDICATOR



- COMPLETELY MECHANICAL—Entirely free from troubles due to leakage of highpressure fluids or to temperature changes.
- EMPLOYS MOVEMENT OF CAMERON PRESSURE GAUGE—Field proven on thousands of operations.
- EXTREMELY RUGGED—Despite its sensitivity, the Type "C" Weight Indicator is ruggedly constructed to give years of trouble-free service.
- READS LOADS DIRECTLY IN POUNDS —Not "points".
- SENSITIVE TO LOAD CHANGES—This feature is particularly desirable for cutting and fishing operations, packer settings, etc.
- INSTANTLY ADJUSTABLE—Quickly adjusted to handle any number of lines.
- EASILY READ—Day or night. Large dial and numerals. Electrically illuminated.
- EASILY AND QUICKLY INSTALLED—No special tools required.

Write for Descriptive Bulletin.

Easily Adjusted to Fit Any Size and Number of Lines

Interchangeable wire line shoes to fit any size line.

Clamp nut holds concave end of shoe firmly against wire line.

Extended handles on clamp nut permit hand tightening.

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predictions of reservoir performance, is a relatively new science and has made rapid progress and appreciable contributions to conservation and greater recovery of oil and gas.

In cycling projects, the pattern of injection and producing wells to give maximum recovery of liquid hydrocarbons is determined by electric model studies. This technique makes use of the fact that the distribution of pressure differentials in gas reservoirs is the same as the distribution of electrical potentials in an electrical field.

Pressure maintenance and secondary recovery projects, the planning and execution of which require engineering service, also may be grouped under this heading of reservoir engineering. By these operations, deficient reservoir energy may be supplemented by gas or water injection to obtain greater recovery of oil.

Well spacing, another problem that has demanded the attention of petroleum engineers, will continue to be a field for engineering study for the future. Many oil fields like East Texas have been drilled to a much greater well density than is necessary for a maximum recovery of oil at a greatly increased cost of producing the oil. It is the petroleum engineer's job to determine the minimum number of wells that need be drilled to effect maximum recovery from oil and gas reservoirs, so that the cost of petroleum products will be a minimum.

Conservation of oil and gas. Conservation of oil and gas, some of the Nation's most valuable resources, is a most important assignment of the petroleum engineer. In fact, a petroleum engineer justifies his existence by conserving oil and gas resources and materials needed to develop them. Petroleum engineers have rendered a valuable service in developing and presenting the facts that have resulted in our present conservation laws. This work is by no means finished. Further conservation of natural gas is a subject before the industry at the present time. Natural gas in the earlier days was considered merely a by-product in the production of oil. Today, natural gas is recognized as an important hydrocarbon resource and is being conserved, gathered, and utilized wherever economically feasible. The scarcity of material during the war deferred many gas-conservation projects that are now getting under way. This is an important field of expanded activity for the petroleum engineer. More natural gas is being gathered and processed in gasoline plants and recompressed for industrial uses than ever before. Some of the products manufactured from natural gas are: Carbon black, gasoline, materials for synthetic rubber, a wide line of chemicals, components of plastics, and important materials for textile manufacturing. Petroleum engineers can render a valuable service by developing means that are economically sound for elimination of all waste gas.

Proration of production. Proration of oil and gas production is a legal and an engineering problem. Laws have been established defining the rights of ownership in the various oil-producing states, and state governmental agencies have been established to administer these laws. Operating regulations, which have been of great value in bringing about orderly development and efficient production of oil, have been formulated under such laws through the co-operative effort of the engineers, operators, and state agencies. The rules and regulations of these agencies in prorating production have recognized engineering principles in distributing the production.

Workover jobs. By workover jobs is meant well repair, reconditioning, or cleanout jobs. The cost of these jobs, in many cases, is far too high for the results obtained. In some cases, the cost of a workover job on a well is as much as the original cost of the well. There is certainly need for improvement and that is the petroleum engineer's job. In new fields, by early recognition of reservoir conditions and the application of the proper type of well completions for these conditions, many future workover jobs should be eliminated. In addition to workover jobs resulting from failure to recognize reservoir conditions, many workover jobs result from mechanical failures. The petroleum engineer should continue to endeavor to develop better cementing methods to exclude free-gas and water production from wells and better equipment and methods to prevent sanding up of wells and corrosion failures. Better methods of increasing production from wells by acidizing, shooting, and paraffin removal are also in the field of petroleum engineering.

Salt-water disposal. Salt-water disposal is becoming more and more a technical problem. Proper conditioning of salt water for disposal into streams and bays in a manner that will not cause damage to property or to marine life, and conditioning of salt water for subterranean disposal frequently requires expensive conditioning of the water. It is particularly expensive in some cases where ten or more barrels of salt water must be disposed of for each barrel of oil produced. The elimination of minute quantities of oil from salt water and the elimination of precipitants or other solids that will clog disposal formations is frequently a complicated chemical and filtering problem.

Handling and separating well fluids. The proper separation of well fluids into gas, liquid hydrocarbons, and water, and the handling of these fluids with a minimum loss of hydrocarbons, is a technical problem of considerable magnitude. The proper separation tmperatures and pressures are frequently determined by analyses of bottom-hole samples or recombined surface samples of well fluids, and the equipment installations are designed for these pressures and temperatures and for the desired capacity. The objective is to minimize the loss of volatile hydrocarbons by evaporation and the loss of crude oil in the form of an emulsion with the produced water.

Treating of crude oil emulsions at a minimum cost usually requires laboratory and field testing of different chemicals with that particular emulsion, and variation of treating temperatures to determine the temperature at which best results will be obtained without causing excessive evaporation losses from high treating temperatures.

High salt content of crude oil, usually resulting from high residual salt-water content, is objectionable from the standpoint of damage to refinery equipment and it is, therefore, desirable in field treating operations to reduce the salt-water content as much as is economically feasible. With some crude oils it is very difficult to reduce the salt content to an acceptable amount by present field treating methods, and better methods will have to be developed.

As mentioned heretofore, under the subject, "Salt-Water Disposal," the removal of oil from the salt water as well as salt water from the oil is the desired objective, in order to reduce salt-water-disposal problems.

Many crude oils congeal at relatively high temperatures and cause troublesome accumulations of paraffin in well tubing, flow lines, separators, and tanks. The solution to the problem in any one field usually requires trial of different methods, such as mechanical, chemical, and heating, in that particular field to determine which is the most economical. There is certainly room for improvement in present methods.

Artificial-lift methods and equipment. Selection of artificial-lift equipment for any oil field should begin first with a thorough understanding of reservoir conditions and an estimate of future production rates and probable reservoir performance. It is necessary to know the probable height that fluid will have to be lifted in wells and the amount of oil and water production to provide for before the proper size and type of lifting equipment can be determined. The choice of lifting methods, that is, gas-lift versus pumping, will be influenced by the availability of high-pressure gas, cheap electric power, sand production, corrosion conditions, straightness of holes, accessibility of locations, size of casing, gas production, cost of equipment, probable life of well—the ultimate objective being to select the method and equipment to lift oil at the lowest cost.

There are many possible applications of engineering for making work easier and for reducing costs on leases. For example, time clocks have been installed on many electric pumping wells for automatic starting and stopping, and for timing and pumping interval to recover the maximum amount of oil with a minimum of wear on equipment. Another application has been the adoption of lighter and stronger electric transmission lines, such as combination aluminum and steel strands in place of copper, which permits wider pole spacing and, consequently, lower transmission line costs. Another example is the use of the Y-connected 762-volt lease electric transmission system in place of the conventional Delta 440-volt system, with an appreciable saving resulting from the

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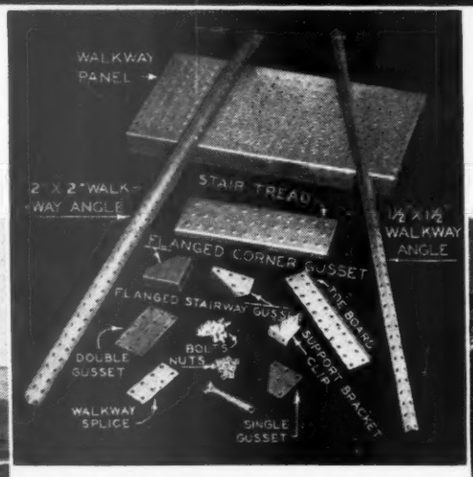
BLACK, SIVALLS & BRYSON (INC.)
B S & B
(TRADE MARK)
OKLAHOMA CITY OKLA.

B S & B SAFWALK MATERIAL FITS TOGETHER LIKE A GROWN-UP ERECTOR TOY



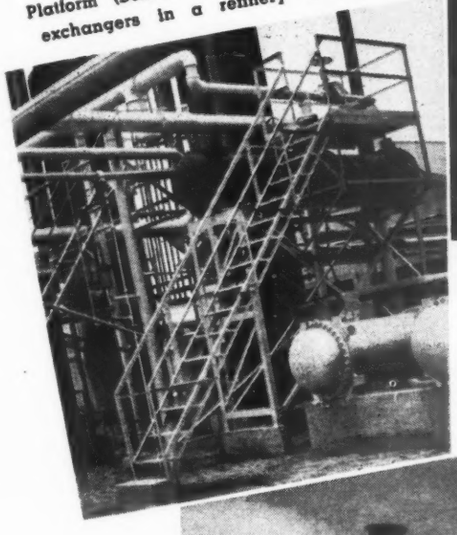
Standard **SAFWALK** Parts (Above) make practically any operating platform for oil field or refinery.

●

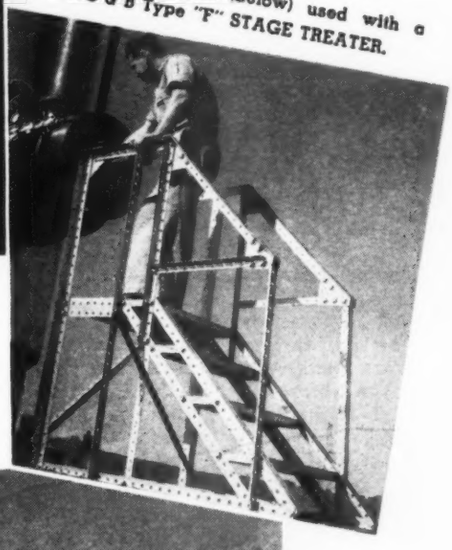
Well Control Valve Platform (Below) in a Canadian Field.

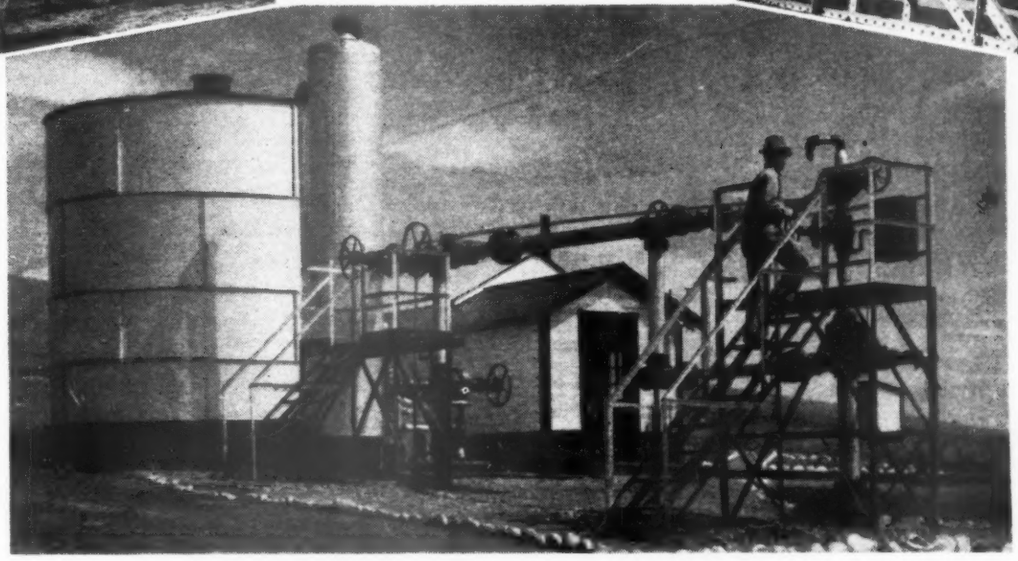
B S & B SAFWALK MATERIAL IS "CARPENTERED" TO THE JOB IN THE FIELD

Platform (Below) used to service heat exchangers in a refinery installation.



Operating Platform (Below) used with a B S & B Type "F" STAGE TREATER.





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- Oil & Gas Separators
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Ask Your B S & B Man

use of smaller conductors. Centrifugal pumps for oil and water service have been found to be more economical in many cases than the conventional oil field plunger pump.

Equipment service records. Downtime and equipment service records, which include operating labor, transportation, replacement, and repair costs on equipment, are essential for determination of the most economical equipment and methods of operation.

Although the regular clerical staff keeps these records, the petroleum engineer usually initiates them and analyzes the results.

Lubrication. A useful service that has been rendered by petroleum engineers in many organizations is the introduction and distribution of lubrication charts for all drilling and production equipment. Such charts describe the kind of lubricant to use for various parts of equipment, the frequency of lubrication, and oil changes where necessary. The type lubricant for the different services and temperature conditions is described. These charts are helpful to both operating and warehouse personnel because careful consideration has been given to minimizing the number of different types of lubricants that must be kept on hand. Economies are effected by such charts not only from better care of equipment but also from the elimination of cases where more expensive lubricants are used than are necessary. For example, there is no need for using motor oil that is specially designed for high-temperature internal-combustion-engine service in pumping-unit gearcases and in steam-engine crank cases.

Corrosion. Corrosion affects, to some degree, all equipment used in producing operations. Corrosion losses are usually expressed in terms of the cost of replacing or repairing the corroded equipment. The estimated annual loss by oil producers is $75,000,000, but this estimated expense might be low because the exact condition of casing and tubing in many wells is not known and it is assumed that in many wells corrosion is not serious. Corrosion frequently results in temporary shut-downs and sometimes in premature abandonment of producers.

The study of corrosion is a highly specialized branch of engineering. As a result of studies made during the past 20 years, numerous changes have been made in equipment and materials to find suitable substitutes for ordinary mild steel equipment previously used. Changes have been made in the methods and practices of completing and producing wells because of corrosion. In the last several years, many new corrosion problems have been encountered, such as that found in high pressure condensate fields. The ever-changing conditions in the oil industry, in most fields, and in individual wells make the continued study of corrosion important.

Petroleum engineering laboratory service. In a large organization a petroleum engineering laboratory can render a valuable service by providing basic data for studying problems in drilling and production. The nature of the work handled by a petroleum engineering laboratory is as follows:

1. Cores — determination of permeability, porosity, saturation, nature of fluids in cores, descriptions.
2. Crude oils and lubricating oils—chemical and physical tests, impurity content.
3. Drilling fluids — physical properties, effect of specific additives on physical properties.
4. Water—drinking, boiler, and engine cooling water; oil and gas well waters; analysis, recommended treatments, correlation.
5. Gases—B.t.u. nonhydrocarbon contents.
6. Scales and deposits—from boilers, engines, lease equipment.
7. Corrosion products—determine nature and probable origin.
8. Metals — chemical and physical tests for corrosion work and selection of materials. Examination of equipment failures. Includes photographic and photomicrographic work.
9. Cements—testing cementing materials for soundness and for properties such as pumpability of slurries and setting under various conditions.
10. Miscellaneous chemical and physical testing.

Evaluation of producing properties. The evaluation of producing properties requires the determination of remaining recoverable oil and gas, estimated future production rates, prices for oil and gas, operating expenses, new investment, and salvage value of equipment. The training of the petroleum engineer qualifies him for handling this work.

● **Management of materials.** The petroleum industry consumes a vast supply of materials and the cost of such material is a major part of the cost of operations. In a year's time drilling and production operations in the United States entail an expenditure of approximately $350,275,000 for machinery and supplies. It is the responsibility of the petroleum engineer to scrutinize such expenditures. Large savings in the cost of materials are effected as a result of the efforts of petroleum engineers in the work of (1) standardization of oil-field equipment, and (2) planning of material requirements to provide the proper material when needed with a minimum of stocks on hand.

Standardization of equipment. In the preparation of acceptable standards, emphasis is placed on (1) interchangeability of product irrespective of the make; (2) reduction or simplification of the number and size of the several items of equipment generally used by the industry, and (3) the design details that are essential and yet are peculiar to the needs of the oil industry. The development of standards of performance and test procedure is also a part of the work of standardization. Standardization is a joint effort of the petroleum engineer and of the manufacturer, and effects large savings for both the consumer and the manufacturer as the result of quantity production, a better product, and the reduction of field warehouse stocks because of interchangeability. During the war, petroleum engineers were required to serve on committees appointed by the Government to consider the conservation of critical materials and to recommend suitable substitutes and alternate standards.

In this field of endeavor, the petroleum engineer has been able to render great assistance to his company by writing specifications on materials based on the results of his detailed investigations, mechanical analyses of equipment, comprehensive field and laboratory testing of equipment, and the compilation and analyses of extensive records of performance. These specifications facilitate requisitioning material in the field, permit placing orders without delay on a strictly competitive basis, and greatly simplify the work of identifying and warehousing materials in the field.

Management of material supplies. The petroleum engineer, being active in current operations and in the planning of future operations, is in an excellent position to plan and coordinate all material requirements; that is, to see that the proper quantity and kind of material is requisitioned, that requisitions are placed in time to receive material when needed, and that stocks of material are kept to an absolute minimum. Continually changing plans of operations causes continual changes in material requirements, and without vigilant planning, there is always a threat of either excessive stocks or shortages that may result in shut-downs or purchase of more expensive equipment in an emergency. In the event of surplus material, either new or used, the engineer can develop means of substituting this surplus on current requisitions. He can also recognize obsolete material in warehouse stocks and save handling and storing costs by disposing of it immediately.

Large sums of money are expended in the repair and reclamation of material. The engineer can make worthwhile savings by (1) carefully investigating the economy of this reclamation work, and (2) supervising the repair of all major items. Before authorizing expenditures for repair of material, the engineer must make sure that the performance and additional service-life to be obtained from repaired material will economically justify such repair in preference to purchasing new material.

● **Reports on operations.** Management must have accurate and up-to-date information on operations at all times as a guide to future operations. The mass of operating reports that are compiled each day must be consolidated into brief reports with a definite meaning and objective so that necessary information can be derived therefrom as quickly as possible. The sifting, consolidating, and presenting of this information is usually the petroleum engineer's job. Some of the reports prepared are: (1) Oil production, (2) Gas production, (3) Salt-water production, (4) Production shortages on allowables, (5) High gas-oil-ratio wells and production penalties

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therefrom, (6) Salt-water producing wells, (7) Number of oil and gas wells producing by various methods, (8) Wells not producing and reason, (9) Wells drilled, (10) Wells abandoned, (11) Drilling rigs operated, (12) Drilling time analysis, (13) Performance of reservoirs, and (14) Daily, weekly, monthly, and annual reports on operations with an analysis of trends and recommendations for future operations.

● **Control of expenditures.** In the operation of a business, management must know at all times the status of receipts, expenditures, the bank account, and current profit. Petroleum engineers assist with this work by consolidating and analyzing much of the cost information on drilling and producing operations. Some of their duties are: (1) Preparation of the budget, (2) Analysis of drilling costs, (3) Analysis of production costs, (4) Trends in costs and explanations thereof, and (5) Presentation of cost information to management in the most usable form.

● **Construction work.** The construction work in large organizations is usually handled by civil engineers rather than petroleum engineers. This work consists of all construction work in connection with such installations as derricks and foundations, roads, canals, gasoline plants, pipe lines, camps, and camp facilities. In a small organization this work and the regular petroleum engineering work might be handled by one general engineering staff.

● **Research.** Research is an important technical function in oil production operations. The purpose of research is to develop the basic methods, materials, processes, and techniques that find their application through engineering. The research of today becomes the engineering of tomorrow.

Because of the specialized nature of most research, stress is laid on thorough scientific, rather than engineering, training. To qualify for original research, the technical student usually must have had advanced work in mathematics, physics, chemistry, or other sciences, and must be prepared to specialize still further along certain fundamental lines. Creative ability is an absolute essential for success in research.

● **Practical experience.** Upon completing a course in petroleum engineering and before undertaking the job of developing improved equipment and methods, the petroleum engineer first must have close contact with actual field work and an understanding of labor's problems in the operations involved. The best way to accomplish this is for the petroleum engineer to have actually performed various labor jobs over a period of a few years, either during school years or immediately thereafter. The petroleum engineer will find this experience invaluable in later years in visualizing whether new equipment or methods will work. It will also give him a confidence in his ideas, and an ability to put them over which he can not get otherwise.

● **Conclusion.** A sound technical training is essential to successful application of petroleum engineering, the same as in other branches of engineering. The universities render a valuable service to industry by providing this training.

In addition to a sound technical training, the other qualifications desired in a petroleum engineer are the same as those desired in other employes; that is, ability to think straight, drive, ability to get along with others, and willingness to accept responsibility. A business organization must function as a team, with each employe doing *what* is expected of him at the *time* it is expected of him. The petroleum engineer must give assistance to other employes wherever possible to help them with their undertakings, and in turn, *win* cooperation from them to help him.

As for the future of engineers in general, I quote from a paper by Donald B. Gillies, vice president of Republic Steel Corporation, in the July 1939 issue of *Mining and Metallurgy:*

"Recently Karl Taylor Compton, president of the Massachusetts Institute of Technology, made a survey of some 500 corporations. This survey brought out the astounding fact that today an engineer . . . is twelve times more likely to become the president of his company than is a nonengineer, five times more likely to become treasurer, and thirty times more likely to become an officer of his company." ★★★

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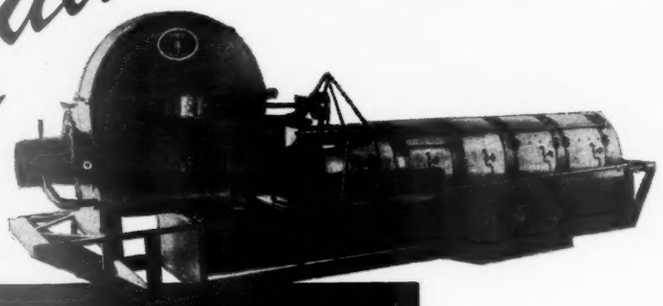

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The Economics of Water Flooding*

By K. B. NOWELS†

CONSIDERABLE information has been written concerning the utilization and possibilities of water flooding as a secondary agent in oil recovery; we have read technical articles describing the installation of water floods, the mechanics of water drive and the various problems involved. Very little has been said or written, however, concerning the most fundamental question of all, "Does water flooding pay?" "What about the costs of flooding, isn't it too expensive for the 'little fellow' and not remunerative enough for the large company?" "What about the economics of water-flooding?"

Failure to more completely realize the possibilities of flooding among western oil producers no doubt is attributable to the fact that water flooding originated in the old Bradford field of Pennsylvania during a time when flush oil fields of the Mid-Continent areas were crowding the headline news. Such a thing as compulsory curtailment and proration by state regulatory bodies had never been dreamed of. Water flooding began in a modest way and in many respects, like Topsy, "jes grew up," unheralded and unheeded by oil operators outside of the Pennsylvania districts.

There was a certain amount of mysticism prevailing, too, which seemed to indicate that water flooding in other oil producing regions outside of Pennsylvania would never work at all; that the Bradford sand had certain qualities and was of such a uniform consistency or permeability that flooding would be operative there and no where else. It was said also that fresh water was necessary for the successful operation of a flood and that other types of water predominating in the Mid-Continent areas would be unsatisfactory.

The laws of physics, however, have not been repealed and unhampered by state boundary lines are operative equally well in Oklahoma, Texas, Pennsylvania, or any other oil producing region. Eleven years ago this summer large scale water-flooding projects were installed for the first time in the Mid-Continent area in the old Nowata oil field of Oklahoma. Much has been written and published concerning these enterprises. None of this will be repeated, except to say that it took the installation of a real "live" water flood at the back-door of the Mid-Continent region to force the realization that perhaps here after all is a secondary recovery method capable in most cases of an initial discovery performance and the possible recovery of quantities of oil greater than those provided by the first cycle of natural production. Success of the Nowata floods has brought some of the large companies into the ranks of water-flood producers and the discovery that, generally speaking, net profits from this type of production during an era of production control, are as interesting as those afforded by wildcatting and flush fields.

The recovery of additional amounts of oil from an oil-producing reservoir, over and above the amount that can be procured through natural production methods, is conservation of the highest type. It means the redemption of millions of barrels of oil that would otherwise be lost. It is common knowledge among most oil men and certainly the technicians, that only a fraction of the oil accumulated by Mother Nature in her underground reservoirs has been recovered by means of the natural forces that control production, particularly in those reservoir bodies unflushed by a natural water drive. There are literally thousands of acres of shallow oil producing territory now standing idle or plugged and abandoned that can be revived by intelligent application of water flooding.

In one sense of the word, it is strange commentary on Man's way of doing things to see him drill to greater and greater depths and complete dry holes and producing wells at costs of thousands and thousands of dollars when all around him lie shallower accumulations of oil that were temporarily discarded when the fascination of flowing production in other localities and too low a price for crude oil caused their abandonment.

Drilling operations have constantly increased and during the last ten years the known reserves of oil in the United States have increased from about 13 billion to over 21 billion barrels. The existence of such reserves from the standpoint of the public at large creates a very favorable picture, but from the standpoint of the average flush oil producer it is not so attractive. Curtailment of production is with us as a matter of necessity and as a practical matter it has been considered necessary to curtail the production of oil wells as well as that of new wells in a field. There is no doubt that each new oil pool discovered has a right to produce, although the allowable for them has been procured from increased market demand, and robbing the allowables already enjoyed by developed pools. The natural result has been a downward trend in daily per-well allowables and the belief has been expressed several times that the production of all Texas wells will be curtailed to their marginal allowable unless the rate of drilling declines.

As a result of this condition a first class water-flooding project is able to compete with so-called flush production, even at the present price of oil.

At the Fort Worth meeting of the AIME in the fall of 1936 William E. Hubbard, of the Humble Oil and Refining Company, presented a paper entitled, "Economics and Well Spacing in Texas," in which he stated that the completion of 20,000 wells annually in the United States means a drilling cost of close to one-half billion dollars, or about 50 cents per barrel produced. He also stated that the producing branch of the industry was credited with an investment of about 5½ billion dollars, and I think API figures will now show something around 7 billion dollars. With crude at a dollar a barrel the rate of return on investment can be estimated at any figure from about 3 to 7 per cent on down.

Financial analysis of investments and net profits of the petroleum industry, prepared by the American Petroleum Institute several years ago, showed that returns on the investment of this industry over a period of 17 years ending in 1938 averaged slightly more than 2 per cent. The highest return on investment returned during this period was 4.96 per cent.

Joseph E. Pogue, vice president of the Chase National Bank of New York, last November published a booklet entitled "Financial Analysis of Thirty Oil Companies." In this analysis Pogue presented figures that show that these 30 companies with 52.4 per cent of the nation's domestic production averaged a 6 per cent return on invested capital for the prewar years of 1934 to 1939 and an average of 7.9 per cent for 1940-44.

The speaker, through his familiarity several years ago with operations in the large Bradford field of Pennsylvania and some of the operating companies there, is in a position to make a comparison between returns from water-flood properties and those from ordinary producing properties. Within the same period of time included in the API figures, but comprising a total of 11 years operation, results from 15 prominent floods scattered over the entire Bradford field showed a net profit of $3,182,000 on an investment of $6,300,000. This represents 50.5 per cent of the investment, or 4.59 per cent per year, and is more than twice the amount of average return mentioned in the API tabulation for the industry at large. It may be argued that for this period of time Bradford crude was bringing approximately $2.00 to $3.00 per bbl., but off-setting this is the high development cost in the Bradford field due to 1700-ft. drilling and other factors that bring the development costs of flood to $3000 per acre.

For the sake of comparison with something closer home, where shallower water-flood properties are available and no more than $1.00 per bbl. is obtained for the oil, figures were prepared for estimation purposes prior to large scale flooding in the Nowata field of Oklahoma. These preliminary estimates showed a profit of $3,559,000 on an investment for the period of $4,664,000. This represents 76.31 per cent return or 6.93

*Presented at North Texas Oil and Gas Association Annual Meeting, Wichita Falls, Texas, March 2, 1946.

†Mr. Nowels is secondary oil recovery engineer and geologist, Hunter, Nowels and Hunter, Abilene, Texas.

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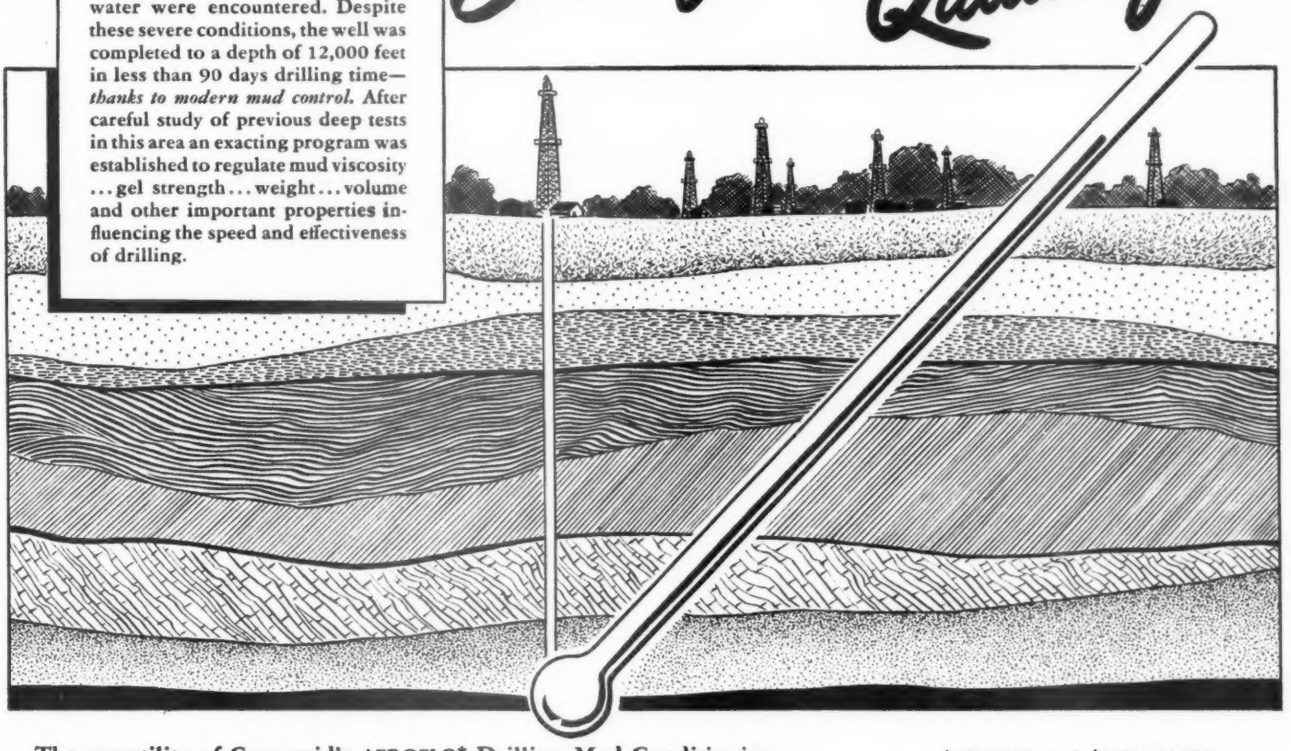

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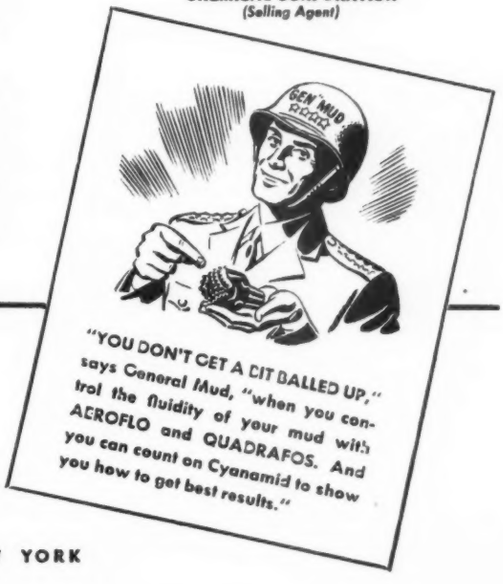
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per cent per year. In the light of actual experience, since Oklahoma water-floods were installed, it is now known that these figures are conservative and the return per year will probably average somewhere in the neighborhood of 7 or 8 per cent. The preliminary estimates were based on recoveries of 4400 bbl. per acre and actually the first flood has now yielded over 7000 bbl. per acre.

It has been my privilege to core-analyze several shallow properties in Texas to determine whether they were suitable for water-flooding purposes. These properties have sands at even shallower depths than exist at Nowata. In the latter field the depth to the Bartlesville sand is approximately 500 ft., and the development cost $800 to $1200 per acre. The Texas investigation covered 350 to 500 ft. depth sand bodies. Because of the more shallow depth it will be possible to develop water floods in this type area for approximately $650 per acre. From the core analysis it is possible to determine with reasonable accuracy the total amount of oil still held in place in the sand and experience, along with laboratory analysis, will show the amount of oil which is recoverable. Such a property as described may rightfully be expected to yield from a sand body 15 ft. in thickness the same per cent of financial return as a Nowata flood, even though it is subject to production curtailment through proration. Drastic reductions in development cost have been possible in Nowata through the elimination of all oil well pumping equipment and the first large water-flood company to enter the field now flow all their flood oil production. This is possible also in other shallow fields.

An extremely informative article entitled, "Large Oil Volume Found Per Drilling Dollar and Foot" by William H. Strang appeared in the September 4, 1939, issue of *The Oil Weekly*. Strang presented figures for the period from 1935 to 1938, inclusive, which reveal that the operator with average success found $3.89 worth of oil for every dollar spent for drilling activities, and 29.8 bbl. of oil for every foot drilled. In the $3.89 figure the cost of production, various taxes and overhead items, and interest charges are not included.

In the first Nowata flood, figured on the same basis Strang used, $220,000 worth of development has so far furnished 1,100,000 bbl. of oil, or $4.90 (also barrels) for every dollar spent in drilling and development. This is 1.26 times the industry average for that period of time. A shallow oil property suitable for water flooding in the North Central Texas area can yield $6.00 to $8.00 worth of oil per dollar spent in drilling and development and 22.6 bbl. per ft. of drilling.

Many other figures and facts could be offered that would also show the advantage of water-flood investments, but these would be too burdensome in a paper of this kind. It is definitely known, however, that a sensibly chosen property properly developed for flooding and intelligently operated will yield a return equal to or in excess of that derived from any other oil production investment.

One of the objectionable features to present day oil production is that production curtailment has increased seriously the "pay-out" period. The pay-out of a well, formerly days or weeks, is now measured in years. Some pay-outs I am familiar with have varied from two to seven years, with possibly a four year pay-out comprising an average. In water flooding, however, due to the quick increase in oil production when once begun and the fact that if properly handled peak production is reached from three to six months after production begins, there is a rapid return of investment and the average good producing flood will pay out in from seven months to a year.

Another attractive feature of water flooding is its inherent adaptability to economic analysis and budget estimate. Cores taken of the oil sand enable an operator to determine the amount of oil in place and the approximate volume recoverable. Practically all risk and element of uncertainty that would be associated with the development of other types of petroleum reserve are removed. The water-flood operator may develop his property at will and treat his reserves as so much merchandise on the shelves. Knowing how much production is necessary to finance his obligations and return the desired profit, he can plan the number of wells needed and all phases of the recovery process.

It is the writer's belief that it will only be a short time until a very intense interest will be shown by all operators in their old depleted and abandoned shallow fields. A considerable number are utilizing air and gas repressuring, which of course is satisfactory and relatively inexpensive, but this method is an intermediate step only and can be followed up with water flooding capable of extracting many more thousands of barrels of oil than was ever possible by the other method. It is more economical to eliminate the intermediate step and procure all the recoverable oil by one method.

It should be distinctly understood, however, that there is something more to water flooding than introducing water under pressure into intake wells in a haphazard manner. It is assumed that the operator realizes the importance of expert engineering advice and guidance and that he will choose a property that core analysis indicates will be successful for flooding. Within the last 10 years the technologist has made considerable advancement in his knowledge of the relationship of oil reservoir fluids and because of this advance an even more accurate estimate of a floods performance can be made.

The writer has been privileged to make a detailed study of the water-flooding prospects in most of the shallow oil producing areas of the country, and in so doing it seemed highly desirable to develop some "rule of thumb" method with which to judge a flood prospects general value in advance even of a detailed core examination assuming, of course, a satisfactory oil saturation, in other words, to arrive at a quick decision as to the relative merits of different prospects after knowledge is had concerning depth, sand thickness, price of oil, etc. Obviously the prospect that has the thickest sand at the shallowest depth will present the better opportunity for profit.

Keeping this in mind, I endeavored to use an index number scheme that might give a rough estimate of potential possibilities. In developing such an index number, it was decided that it might be in order to divide the number of feet of oil sand by its depth in hundreds of feet. In other words, a 10-ft. sand lying at a depth of 200 ft. would have an index number of 5, which of course is the result of dividing 10 by 2. Ten feet of sand lying at a depth of 400 ft. would have an index number of 2.5, etc.

If crude oil prices were the same in all fields, and if the same operational and development costs existed throughout, it would be easy after sufficient analysis were made to perhaps say that all fields having an index number of 1.5 or greater would be suitable prospects for profitable water flooding at the present price of oil. Crude oil prices are not the same in all fields, however, and obviously some correction has to be made for difference in price. For instance, in Bradford where the producing sand is all the way from 1100 ot 1800 ft. in depth and 20 to 50 ft. in thickness, we would have index numbers of the magnitude of 1.50 to 4.50. By experience we know that water flooding in Bradford has been profitable and from this standpoint it could be said that any field that has an index number of from 1.5 to 4.5 would be profitable. Of course this is not true, because Bradford has been successful at that depth and low sand permeabilities because of the $2.00 to $3.00 price for oil that they have always enjoyed; whereas Mid-Continent fields have one dollar oil and naturally an index number of, say, 1.5 would give an erroneous picture of the Mid-Continent flood prospect.

In an effort to correct our index number for the price of crude oil, I have brought this correction into place by using the reciprocal of the crude price, which to be more explicit is one divided by the price per barrel. In other words, for $1.20 crude the reciprocal would be 1 divided by $1.20 or 0.835; for $2.50 crude the reciprocal would be 0.40. Using this reciprocal correction, an index number of 1.75 for Bradford now becomes 4.37, which is 1.75/0.40; whereas an index number of 1.75, for instance, for Texas oil would become 2.06. This is another way of saying that the Texas prospect would be a little bit less than half as good as one in Bradford.

This relationship is not exactly correct, due to the fact that oil saturations vary, development costs differ due to local conditions, and a proportionately higher index number does not always mean a relatively higher profit per acre. In general, however, I feel that as time goes on and more study is given the question, it will be possible to correct for all factors involved. For the sake of con-

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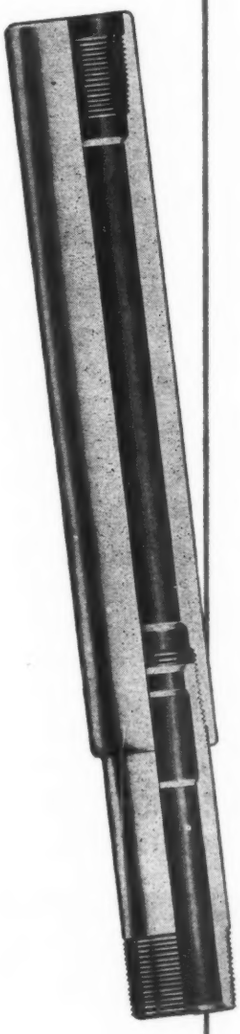

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venience, however, it is a help to me to use this index number scheme for hurriedly trying to determine whether a certain prospect has value under present crude prices. I feel that for all practical purposes, if a prospect is up for consideration that has an index number of 2.5 or above it will bear detailed study.

The importance of adequate core investigation should be re-emphasized along with the necessity of making floodpot oil recovery tests. It could be that the oil is too viscous to flood properly, or that there is too high a connate water content to permit the sand yielding the desired amount of oil recovery. In the interpretation of core analyses we formerly applied an experience recovery factor and said that if the analysis showed so much oil in place, it would be possible to recover 40 or 50 per cent of it. Maybe you can and maybe you can't. Find out!

Like every other phase of development in the oil industry there have been good, profitable water floods and there have been poor ones. In practically every case the writer knows about poor floods have resulted from improper examination and consideration to start with, or the failure to follow the engineer's advice.

I know of a lease that was purchased for water-flooding purposes because a lone core analysis made years ago by a major company indicated that there were 18,000 bbl. of oil per acre yet in place. Core analyses subsequent to the purchase of the property showed disappointingly low oil content, and only about one-fourth to one-sixth the amount shown by the old core. With all due respects to the major company, it should be said that their analysis was made prior to current well established laboratory procedure now used.

Even the most experienced water-flood operators are known to have become careless and neglect the proper core analysis and interpretations. One of the largest operators in the Bradford field a few years ago made a "million dollar bust" in the development of a property because the cores looked good, when analyses properly interpreted would have shown the inadvisability of developing the property because of the excessive amounts of connate water.

It is my firm conviction that in the future our oil control and curtailment agencies will realize the tremendous importance of conserving the large amounts of oil trapped in our various old, semi-depleted fields that await the utilization of water flooding to make this oil available. I predict that the time will come when recognition of this type production will cause the removal of all proration and curtailment regulations from secondary recovery. May I suggest even now, that our regulatory bodies consider the removal of production restrictions from this type production. With secondary recovery unhampered by production curtailment in Texas and a permanent increase in price for secondary recovery oil even greater interest will be shown in doing a better job of recovering oil than we have done in the past. ★★★

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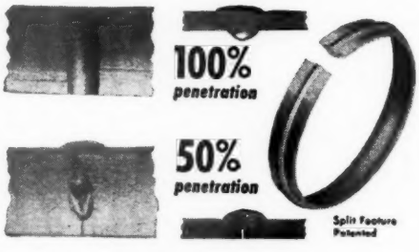

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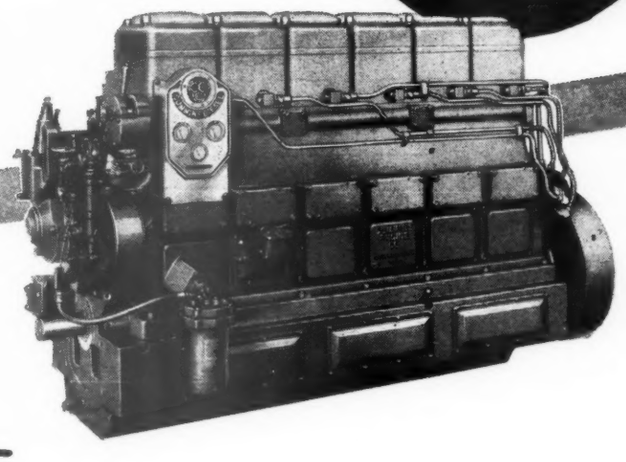


CUMMINS ENGINE COMPANY, INC., COLUMBUS, INDIANA

Gas Recovery Systems*

By DOUGLAS ROGERS, JR., South Penn Natural Gas Company

● **Abstract.** Gas recovery systems have been developed to a high degree of efficiency in the Bradford field in Pennsylvania and New York. These systems recover solution gas from separators and stock tanks and supplement the lease fuel. The gas is removed at low pressure or vacuum from vapor-tight systems which are protected by safety devices. These systems can be operated by automatic controls and when properly designed and installed require very little attention and maintenance expense. Gas recovery is profitable only in areas where natural gas is costly. For maximum efficiency and financial success the installation of such systems should always be preceded by a thorough study of the property, its production, and facilities.

● **Introduction.** This paper was prepared by Mr. Rogers as a member of the API Standing Subcommittee on Secondary Recovery Methods, of the Topical Committee on Production Practice, as a part of its current study of "The Development and Operation of Secondary Recovery Projects," November. 1945.

● **Fundamentals of gas recovery.** In many of the shallow stripper fields gas is becoming a relatively scarce, and consequently valuable, commodity. Obviously in areas where gas is at a premium its recovery, even in minor quantities, can appreciably affect the economics of secondary recovery operations. This has been particularly true of the Bradford region in Pennsylvania and New York and it is hardly surprising that gas recovery has been more highly developed and is in more extensive use in that area.

During the past seven years a number of articles have appeared in the trade journals describing various gas recovery systems used in the Bradford field. This paper will confine itself to presenting a summary of the essential features of such systems.

A definition of the terms "gas recovery" is advisable here. In this paper gas recovery refers to the salvage of solution gas escaping from produced crude oil either at low pressure or under vacuum, and the use of such gas as lease fuel.

The amount of gas which can be recovered from a barrel of produced crude oil depends on the gravity and temperature of the oil, and the pressures under which it is handled. Evaporation losses in the Mid-Continent area[1] in 1921 averaged 6.2 per cent during the movement of the oil from well to refinery. About 3.5 per cent, or 56 per cent of the total loss, occurred on the producing leases. Vapor-tight tanks and equipment were found to reduce lease losses to less than 1 per cent. Carlson[2] states that year-round surveys made on producing properties in the Bradford field showed losses ranging from 1.6 to 5.2 per cent and a number of tests were also made to determine the amount of gas lost per barrel of crude produced. The volumes recorded ranged from 20 to 66 cu. ft. per bbl., or an average of 43 cu. ft. per bbl. The highest figures were obtained from new wells in new water floods; the smallest from wells in old watered-out areas.

Bissey and Yuster[3] published the results of laboratory experiments on Bradford crude which compare favorably with Carlson's data above (Fig. 1). Their work indicated that when oil is shrinking at the rate of 3.0 per cent, it is losing 49 cu. ft. of gas per bbl.

The above figures prove that secondary recovery operators lose both valuable natural gas and oil production when they fail to control, and recover the products of, crude oil evaporation.

● **Mechanics of gas recovery.** Gas recovery in the Bradford field is effected at the gas-oil-water separators and stock tanks. Fig. 2 shows a typical set-up[4]. Oil, gas, and water enter the separator tank from the lead line, a bleeder line being used when necessary to take the gas directly to the separator dome and thus prevent surging. Water is syphoned from the bottom of the separator and oil gravitates to the stock tanks. The gas recovery line takes gas from the top of the stock tanks and from the separator dome. Liquid seals are placed in the line connecting the separator tank to the stock tanks and in the lines between the stock tanks.

The gas recovery line delivers the solution gases either directly to a vacuum pump or to a vacuum gathering system. To guard against excessive pressures or vacuum being exerted on the tanks or separator a pressure-relief device is connected to the gas recovery line. This is a specially built liquid seal that vents to the atmosphere whenever the pressure or vacuum in the system exceeds predetermined limits.

Some companies use separators in

FIG. 1. Gas volume plotted against loss in oil volume. *(After Bissey and Yuster)*

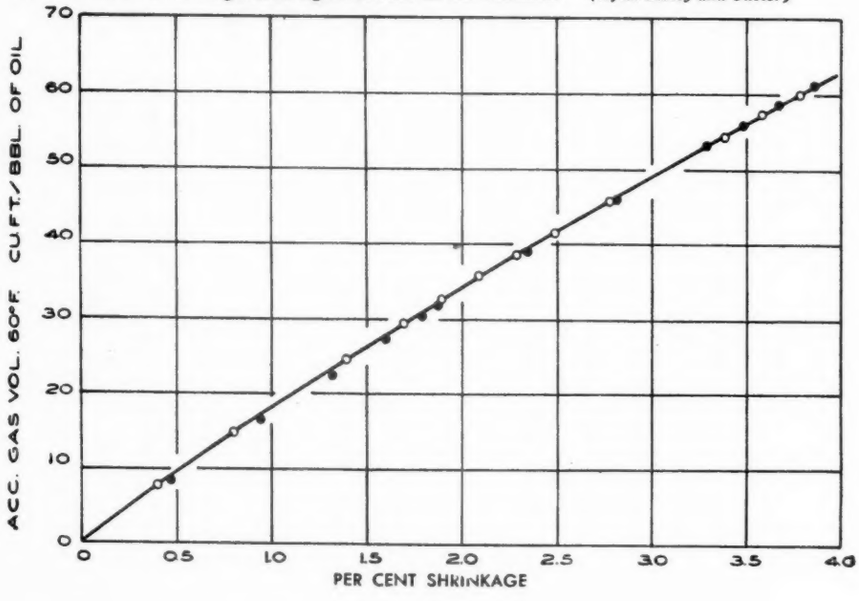
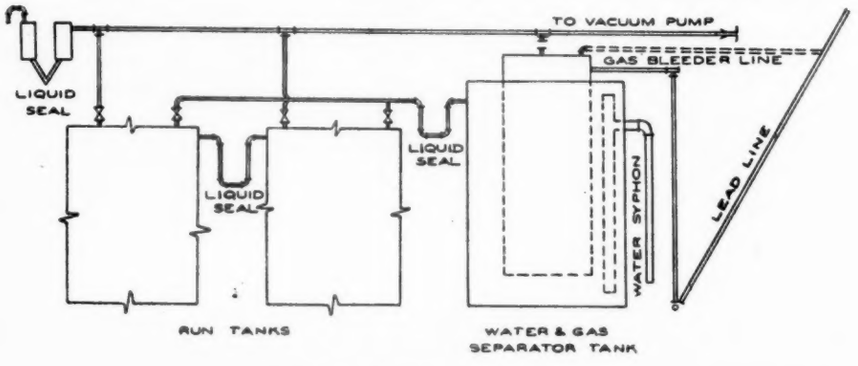


FIG. 2. Typical gas recovery system. *(From "Operating Practices," Producers Monthly, Oct. 1943)*



*Presented before Eastern District Division of Production, American Petroleum Institute, Pittsburgh, Pennsylvania, June 13, 1946.

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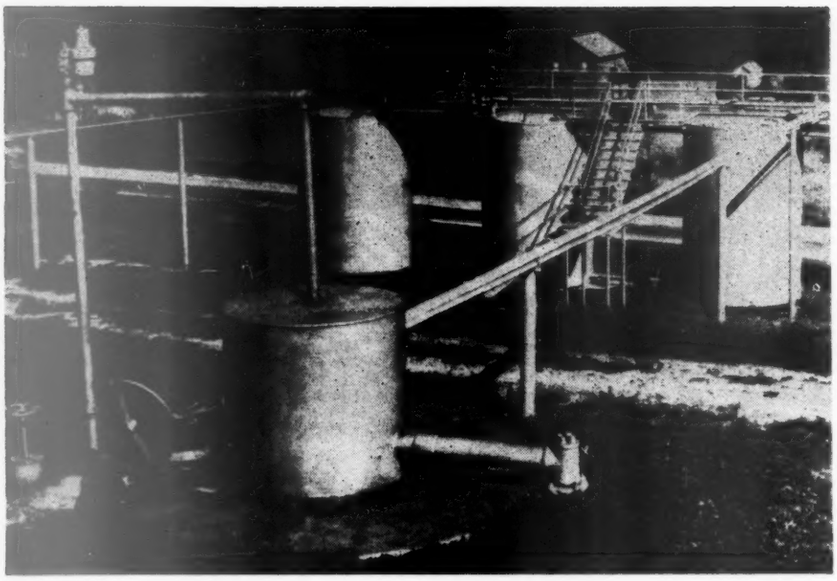

Gas recovery system near Bradford, Pennsylvania, syphon-type separator (buried) in foreground.

which the oil and water levels automatically adjust the outlet flow by float-operated valves (Fig. 3). These may be equipped with baffles or perforated pipes which break up the mixture entering the chamber and help to "strip" it of its solution gas. Float-operated separators should be housed in a building to protect them from the dangers of freezing and corrosion. As shown in Fig. 3 the lower float, which operates the water outlet valve, moves up and down in a cylinder. This cylinder is closed at the top and open at the bottom, thus preventing the entrance of viscous oil-water emulsions which might disrupt the critical balancing of the float.

Usually neither of the above types of separators perform 100 per cent separations of the oil and water due to the presence of varying amounts of oil-water emulsions. To prevent the loss of such emulsified material, a "slop" tank is employed. This tank receives the water run-off from the separator and performs a secondary separation. Slop tanks also help to reduce losses caused by stuck valves, freeze-ups, and excessive fluctuations in fluid flow. To prevent freeze-ups in the syphon-type separator many operators bury them in the ground, leaving only the dome exposed. Rapid changes in flow may overload the separator or its outlet lines and cause loss of oil. It is a good policy when installing such equipment to provide a considerably larger capacity than is necessary to meet conditions of normal flow.

In general the dimensions and design of separator tanks and their connections depend largely on the amounts of oil and water to be handled and the pressures or vacuum to which they will be subjected. They are subject to the ingenuity of the operator and his own special problems. The most important item is to have the system 100 per cent vapor-tight.

The installations described above may be connected to the lease fuel system in several ways. Many operators connect the gas recovery lines to a vacuum pump and boost the gas into their fuel lines. The pump may be operated by hand or by automatic controls. Obviously care must be taken to keep the pressure or vacuum on the separators and tanks from exceeding the limits of safety. One type of automatic installation is electrically controlled. It involves the use of a vaporstat mercury switch (Fig. 4) which can be set to start and stop a motor-driven vacuum pump at any desired pressure or vacuum[4]. For operation during regular periods a belt-driven compressor may be used with a vacuum control valve (Fig. 5) regulating the vacuum on the tanks. Power can be taken from a pressure plant or pumping power.

Another type of installation[5] uses a gasometer to regulate the pressure. The gasometer (Fig. 6) consists of two pipes placed one within the other, welded together at the bottom, and the annulus filled with fluid. Gas entering the center

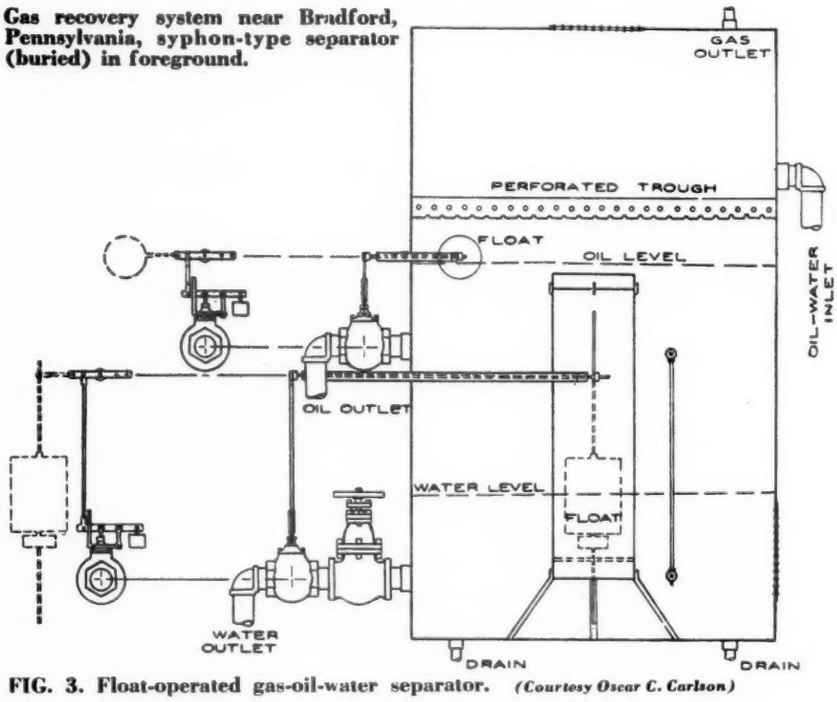

FIG. 3. Float-operated gas-oil-water separator. *(Courtesy Oscar C. Carlson)*

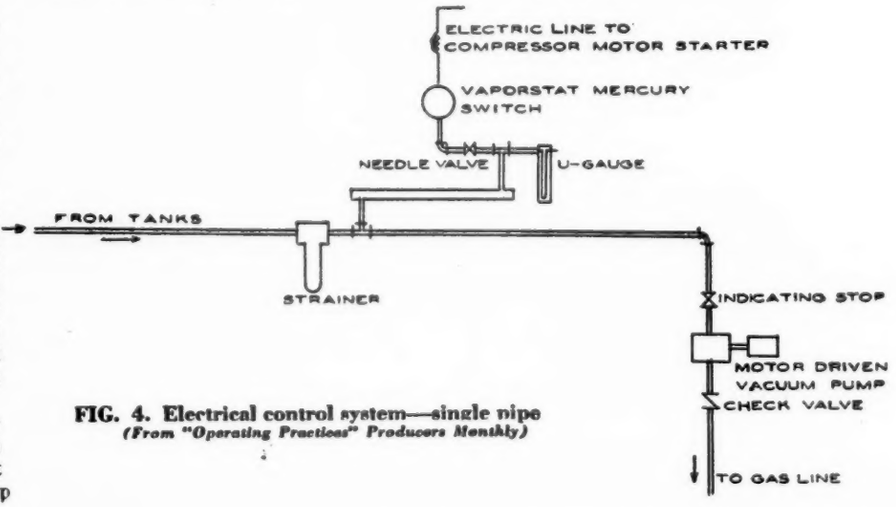

FIG. 4. Electrical control system—single pipe
(From "Operating Practices" Producers Monthly)

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pipe exerts a variable pressure, raising and lowering a floating hood which is attached to a lever which operates a quick-opening valve. When no vacuum-gathering system exists on the lease a second quick-opening valve is installed between the field gas line and suction line. This valve is also operated by the gasometer but in opposition to the first valve, so that a constant supply of gas is fed to the engine regardless of whether or not the gas recovery line is producing gas. However this arrangement is not always satisfactory since the quality and composition of the lease and tank gases may differ considerably[4]. Bissey and Yuster[3] report a distinct difference between casinghead gases, which are highest in methane, and the separator and stock tank gases, which are highest in propane. They state that higher separator and tank temperatures produce a larger amount of gas of higher molecular weight, higher specific gravity, and greater heating value, and that such gas requires more air for combustion. Differences in composition should be alleviated whenever possible by diffusing the various gases in some manner before they reach the gas engine.

Regardless of the type of gas recovery system employed, the equipment should be designed and installed to operate safely and with a minimum of up-keep and attention.

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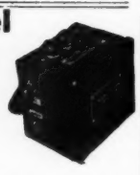

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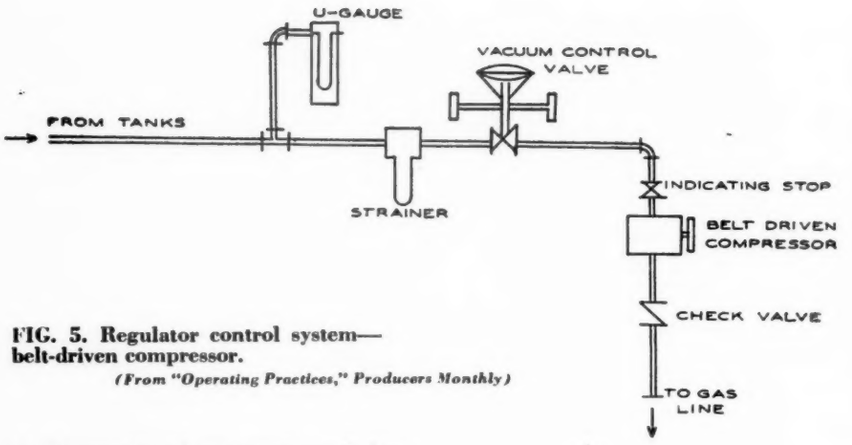

FIG. 5. Regulator control system—belt-driven compressor.
(From "Operating Practices," Producers Monthly)

● **Economics of gas recovery.** It has been pointed out in this paper that gas recovery has reached its maximum development in the Bradford area, where gas is scarce and relatively expensive. It follows that this factor of scarcity will largely determine the feasibility of recovering solution gas in other fields. Where gas is plentiful and cheap the cost of the equipment and its installation will in most cases exceed the financial benefit to be derived therefrom.

Another economic factor that enters the picture to some extent is the price of crude. Bissey and Yuster[3] state that, assuming natural gas costs of 45 cents per 1000 cu. ft., it would not pay a producer to remove gas from Bradford crude when the market price is over $1.80 per bbl. This is a theoretical figure since it applies only in cases where all of the gases produced from the oil could otherwise be held in solution and sold as liquid petroleum. It is extremely doubtful if such a situation could ever be attained under conditions existing in stripper fields. It might be safe to offer a generalization to the effect that, if gas recovery results in an excessive stripping of gas from the crude with a consequent excessive reduction in volume of produced oil, such practice might become unprofitable when the price of crude oil reaches a high enough level. In practice, however, much of the gas that escapes from crude oil will come out of solution regardless of whether or not a gas recovery system is installed and such a system simply acts to salvage that gas. When pressures exceed atmospheric, the rate of evaporation is reduced to some degree, thereby reducing shrinkage. Most producers, therefore, prefer to operate at a very low pressure.

There is one definite effect caused by high crude prices. The normal tendency of the average oil producer who operates under a wide profit margin is to give less consideration to gas recovery as a means of increasing the efficiency and income of his properties.

Obviously, the actual cost of installing a gas recovery system will vary considerably. Such factors as the size of the the lease, the fluid production, and the types and amount of equipment which must be purchased will differ greatly.

An overall preliminary survey of the property should precede any installation. The amount of gas that can be salvaged should be determined as closely as possible and the estimated savings in lease fuel costs used as a yardstick in deciding on the type and amount of equipment to be installed.

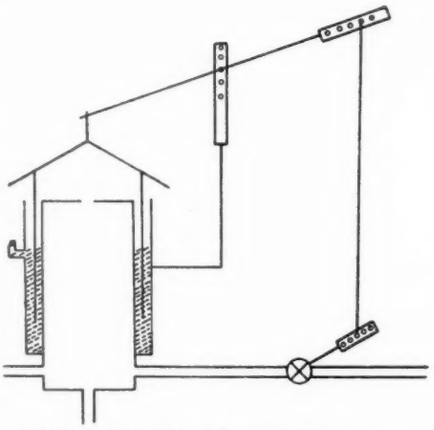

FIG. 6. Liquid seal gasometer.
(After L. T. Bissey)

One operator[6] is known to have saved $400 per month in fuel costs by installing a gas recovery system. Another[7] achieved savings of more than $10,000 per year. Still another[5] experienced increases of from 5 to 15 per cent in oil and gas production on several leases.

By carefully analyzing all pertinent factors an oil producer can determine whether gas recovery will be profitable on his properties, how much initial investment will be required, and how soon a pay-out can be expected.

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★ ★ ★

Evaluation of New Geophysical Methods*

By W. M. RUST, JR., Geophysics Research Division
Humble Oil and Refining Company

● **Introduction.** Last March when you did me the honor of selecting me as president, I hoped I would have the privilege in my presidential address of telling part of the story of the contributions of geophysicists to the war effort, and of attempting some prophecies concerning the contributions of the war to geophysicists' future prospecting efforts. For a time last fall, official optimism reached the point where it seemed that it would be possible to secure the release of some of the story; however, in December, I realized that someone else would have that pleasure. But, in looking forward to the day when we can turn away from our wartime activities, I have had my interest rekindled in an old problem, a problem which, with our present prospecting organizations, is the mutual responsibility of geophysicists, geologists, and management. It is the problem of evaluating proposed new geophysical prospecting procedures and the somewhat simpler but still extremely difficult problem of evaluating modifications of existing methods.

We all remember the anguished cry that only the widespread adoption of new discovery methods could stop the distressing decline of discovery rate. Yet we know what happened when the problem of inadequate discoveries was made more acute by an unprecedented increase in production to oil the war. The number of seismograph crews reached an all-time high. The number of gravity crews reached an all-time high. But what of the crews using new or unconventional methods? Why are they conspicuous tor their rarity? You know the answer. Wisely or foolishly, we were afraid to use them when the heat was on.

I wish that my title, "Evaluation of New Geophysical Methods," actually meant that I was offering an evaluation of a number of new geophysical methods. Unfortunately, at the moment, there is a dearth of proposed methods, sound or unsound. The causes of this scarcity are well known and will end with the war. The unparalleled demand for technical men in the development, design, manufacture, and use of instruments of warfare, has not only drawn the time and thought of nearly all of our research men and many of our operating men but has also turned the attention of free-lance inventors, as well as crackpots, away from the ever-alluring problem of getting rich quick by discovering the answer to the problem of finding oil. This is natural. The problems of war have the obvious appeal of patriotism and, equally important, the stimulus of new and exciting approaches, as typified by radar.

But the war has not dried up the stream of oil-finders' dreams; it has only dammed it up. War has emphasized the vital role petroleum plays in modern life. Over half of the tonnage of war material shipped overseas is made up of petroleum products. Moreover, the pinch of gasoline and fuel rationing in this country has brought the problem home in a very direct and personal way. Everyone knows we must have an abundance of oil. It has also been widely stated that our oil-finding effort is not too satisfactory. Even before the war, we were told by many authorities that our consumption of petroleum was outstripping discoveries at an alarming and rapidly increasing rate. The enormously increased demand for oil brought on by the war and the diversion of the efforts of many men from prospecting, have obviously made the problem even more serious.

It is certain that the rewards, which this situation promises the fortunate inventor, coupled with the availability of wartime technological miracles, such as some of the gadgets which drove the Nazi submarines to cover, radar and other still secret developments, will result in a stream of proposals of new geophysical methods and modifications of old methods. Radar may well replace the witchhazel fork. When this flood comes, from our own men and from outsiders, we will be faced with a two-fold problem of extraordinary difficulty. First, we must recognize and adopt any proposal of real merit. Second, we must condemn, with the least possible expenditure of money and effort, all proposals which have no real merit.

● **Statement of criteria.** Here I hasten to make my second confession. Not only have I no new methods to evaluate for you to-day, I also have no sure and simple system of evaluation to propound. I hope, however, that it may prove helpful, or at least interesting, to discuss a few phases of the problem. Let me first state five criteria which a usable geophysical prospecting method must satisfy. I am willing to make the categorical statement that any method which fails to satisfy these criteria, properly interpreted, is of no value. At first sight, these criteria may seem so obvious that discussion is unwarranted. Perhaps. But the first three are fairly simple to apply and will dispose of a high percentage of crackpots. The last two, which are intimately related, are the ones which require skill, patience and a touch of clairvoyance, to apply with certainty.

First, the method must involve physical measurements of some property of the earth. I use the term "physical" here to distinguish from "psychical" and include chemical, biological, and so on.

Second, the measurements must give reproducible results. The term reproducible will require some explanation.

Third, the process must be able to compete, on the basis of economics, with existing methods. This involves both the cost of operations and value of results.

Fourth, and this is almost a restatement of our problem—the method must have a significant relation to the occurrence of oil.

Fifth, the method must have a teachable interpretation.

● **Discussion of individual criteria.** A consideration of the individual criteria will show that they are somewhat less obvious than appears at first glimpse. The first criterion, that the method be based on physical measurements of some property of the earth, seems one that could cause little argument. I would like to extend this criterion to require that the physical property involved be identifiable. This would, I believe, exclude the wiggle-sticks and unique instruments, which, for reasons unknown to the discoverers, give certain reactions when directly over oil or gas. Even if some Yogi has psychical powers that enable him to locate oil or if by some queer and unknown chain of events, my watch decides to stop whenever I cross a pool of oil, these remain isolated phenomena and unless the laws that govern them can be determined and, in the first case, our seismograph computers taught Yogiism, and, in the second, our instrument makers taught to duplicate my watch, neither can form the basis of a new geophysical method. Under extraordinary conditions we may be willing to waive the requirement that the physical property be identifiable and insist only that a definite series of manipulations leading to a numerical result be followed. We twist the knobs on a little black box according to definite rules and read a scale. If I can be convinced that the resulting scale reading is actually a function of the location where the measurements are made and satisfies my second criterion, I may begrudgingly admit that it is a physical measurement of some as yet unidentified property of the earth, but until I invent a name for the property and discover some of the laws it obeys, I will remain unsatisfied and suspicious.

Suppose now we have a device which gives a physical measurement in this sense. It is of no value unless the elementary data which it gives at a series of stations in an area can be repeated with a sufficiently high degree of accuracy or unless repeatable secondary values can be obtained from these primary data by straightforward computations calling for a minimum of personal judgment. An example of the latter type is given by a

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magnetometer survey where corrections must be made for diurnal variation. This criterion is not too simple to apply. No physical measurement can be made with absolute accuracy. If enough significant figures are retained, repeated readings will always differ. This is often particularly pronounced in geophysical measurements. We must, therefore, decide what we mean by a sufficiently high degree of accuracy of repeated measurements. The error in repetition at an individual station must be a fairly small fraction of the difference between values at stations on and off of the anomaly. Not only must the measurement at individual stations be reproducible but the anomalies obtained in an area by occupying two different but overlapping sets of stations should practically coincide. The data should be smooth in the sense that the variations observed over an area containing an anomaly interpreted as indicating an oil field, should be much greater than the variations observed when the same number of stations are crowded into any small portion of the area. It is true that a method which is basically sound may fail to meet this criterion in the course of any one trial because of instrumental difficulties. But this is a problem for the developer of the method, not the evaluator. Until such difficulties are largely overcome or at the very least readily identifiable, the process should not be called a geophysical prospecting method.

With satisfactory cooperation from the advocates of the method, these two criteria can be applied with reasonable assurance that fairly definite answers to them will be obtained without an excessive expenditure of time, money or effort. The principal requirement, other than careful, conscientious work, is that a sufficiently large region be covered to give both normal and anomalous areas. A method which fails to satisfy these two criteria certainly cannot be used as a practical prospecting method; at best, it may serve as the basis for further research. On the other hand, it is easy to think of methods which satisfy these criteria which are not useful prospecting methods. As a concrete example, I can mention measuring the distance to the nearest hard-surfaced road. Incidentally, it might surprise you how well this method succeeds in finding oil fields!

Before we turn to the difficult and somewhat speculative fourth and fifth criteria, let us look at the reasonably simple third criterion—the method must be economically competitive with existing methods. That is, it must give valuable results not given by other methods at comparable cost. This may be true if it finds oil not found by other methods, even though it may fail to find some oil they can find. It is not necessary for a new method to make all existing methods obsolete in order for it to deserve acceptance. Each individual case must be considered on its own merits. We can, however, determine some general limits. The cost per acre certainly must be less than the cost of drilling closely controlled wells to the maximum effective depth of the method and closely enough spaced so that no commercial deposit of oil or gas could be missed. It seems safe to assume that no geophysical method will give more direct and valuable data than a properly drilled wildcat. At the other extreme, a new method cannot compete with one of the established methods which gives equivalent information at a comparable cost per acre. Within these wide limits, the cost and value of the method must be weighed against one another and against those of other methods by intelligent guessing. In many specific cases, there may be room for arguments, but frequently the answer will be obvious after a moderate amount of study.

The fourth criterion, that the method must give information significantly related to the occurrence of oil will in most interesting cases be difficult to apply. I define the term "significantly related" pragmatically. I will say that a method gives information significantly related to the occurrence of oil, if the information is successful in finding oil, when used to guide a program of leasing and drilling with the same intelligence and confidence that the information from reflection seismograph work is now used.

Two approaches to the application of this criterion are useful. The first is the theoretical. If the theory of the method is well developed and if numerical data on the variation of the relevant physical properties on and off of anomolies are available, it is possible to give a mathematical "Yes" or "No," if the calculations can be carried out without the ne-

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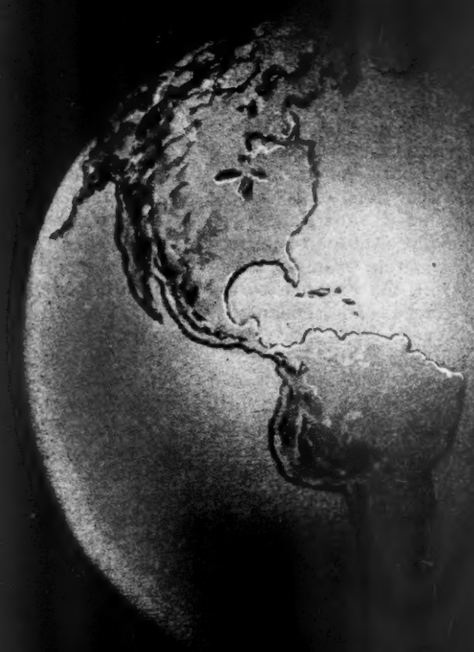

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cessity of introducing approximations which vitiate the conclusions. Three substantial "If's"! Thus, it is possible to say with complete assurance that no refinement of surface gravity methods will permit one to determine the presence or absence of oil in the subsurface. Likewise, it is possible to say that radar methods, depending on the transmission of ultra-high-frequency electromagnetic waves through thousands of feet of soil will not find oil in place. There is, however, a serious danger in theoretical studies of reaching the wrong conclusion by starting from false assumptions. Everyone knows the classic story of the major company that refused to use the reflection seismograph for five years after its introduction because an internationally known physicist, retained by them as a consultant, proved mathematically that the method was unsound. However, even where a final and definite answer can not be obtained from a theoretical investigation of the method, such a study is very useful both in applying the method and in guiding an empirical study by suggesting possible strong and weak points of the method. Whenever possible, it should be part of the evaluation program.

The second approach is the empirical and statistical. A thorough empirical study is a long and costly process. Because of the nature of the technical problems involved, the direct responsibility should be borne by a geophysicist, but because geological data, and often information on future drilling programs, are needed, the geologists are closely involved. Likewise, because the program may well involve very substantial expenditures before a final decision is reached, full support from management is essential.

One of the first and most important steps in an empirical evaluation is the selection of the types of areas and the actual areas to be studied. It is frequently necessary to select a number of different areas for study before condemning a method. Suppose the first tests of the reflection seismograph had been in certain parts of West Texas! Or, suppose the early refraction and gravitational work had not been in salt-dome country! A number of systems for selecting the trial areas has been suggested. A popular and useful system is to select areas where rather comprehensive data, from other geophysical methods and from wells, are already available. This system has the advantage that the results of the proposed method can be compared with those of other methods very quickly. There are, however, some other serious objections to this system. For example, the physical nature of an oil field is changed in many respects during the development process. This may well result in anomalies on the oil fields which were not there before the development. Or, conversely, it may obscure a legitimate anomaly which could readily have been found before development. Nor is this all. The interpreter is very apt to be influenced, one way or the other, by his knowledge that an oil field is there. Even if he is not, any one who examines his work will be inclined to discount the anomalies which occur on oil fields. Thus, both physical and psychological factors conspire to detract from the value of the areas which are occupied by oil fields. The same thing is true, to a lesser extent, of dry holes. Even if there are no oil fields or dry holes, there is some fear that the results, particularly if an important element of judgment is involved, may somehow be colored by the information already in hand. If an area is selected where little drilling has been done, but where the geophysical data are considered good, useful results are obtained where the new and old data agree; but when they disagree, one is in a dilemma. If the old method is assumed to be perfect, there is little point in trying the new method. But if it is admitted that the old method is fallible, nothing is added to our knowledge of the new method. This system, however, is particularly useful in studying methods for which very specific claims have been made. For example, a method which is supposed to locate the edge of production by measurements along a single profile may be quickly disposed of in the woods on the edge of any one of many oil fields. Or, an electrical method which is said to be insentitive to shallow variations may readily be checked by a line across a known shallow anomaly. Such spot tests are necessarily negative in nature. They weed out some unsound methods but do not prove the soundness of the methods which they fail to condemn. In using spot tests, one runs the risk of condemning a useful method because its promotor was over-enthusiastic.

Another system, which has much to recommend it, is to work fairly large areas around locations of wildcat wells which are to be drilled in the near future. This avoids most of the difficulties of the preceding system. It requires much more time and is therefore feasible only for very promising methods. It may be argued that this system gives some advantage to the method under investigation since wildcats are presumably drilled only in areas which seem favorable. This difficulty can be minimized by working a large enough area around each wildcat.

A third system, which on a purely technical basis is the most desirable but which is very expensive if the method turns out to be unsound, is to select a number of rather large areas, prospect them with the proposed method and then drill the anomalies. This gives a very direct answer as far as each particular area is concerned. A disadvantage of this system is that if the method fails in the first area tried, it is very likely to be condemned even though it might well have succeeded in the next area.

Whatever procedure is used in attempting an empirical evaluation of a proposed method, there is a grave danger of demanding an unnecessary degree of perfection. Because of the limitations of the present prospecting methods, a new method could prove to be very useful and yet have a fairly high ratio of failures to successes. According to Lahee, of 596 wildcats drilled primarily on seismograph data in 1943, only 123 were producers. Thus, a new method, which gave one discovery out of each five wildcats, might be a serious competitor of the seismograph in determining locations of wildcats. This contrasts rather strongly with the scale we are likely to use in evaluating a new method empirically. Depending upon such factors as the "reasonableness" of the method and our personal hunches, we are apt to demand that the method find 75 to 100 per cent of known prospects in an area and that from 50 to 100 per cent of the prospects it finds, on which we have other information, should be either oil fields or at least suitable traps. On the other hand, if we lower our standards to a somewhat more reasonable ratio of successes to failures we run into trouble with coincidences and the possibility of those secondary factors which result from the development of oil fields, such as my earlier example of hard-surfaced roads.

By my fifth criterion, the method must have a teachable interpretation, I simply mean that it must be possible for a trained interpreter to derive from the primary data, given by the method, information which is usable in the search for oil and that the process used in deriving this information must be one which may require intelligence, experience, and judgment but not guesses or arbitrary choices. Two skilled interpreters should usually arrive at very similar answers. While I have placed this criterion fifth, it is so intimately tied in with the fourth, that the two must be studied simultane-

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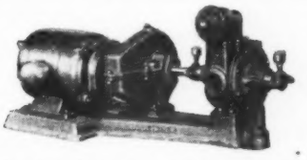

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ously. An interpretation which satisfies this criterion will very likely combine an application of the theory of the method with geological knowledge concerning the nature of the probable oil traps in the region under investigation. This is not absolutely necessary. The interpretation may be based entirely on an empirical correlation between certain observed phenomena and the occurrence of oil. But such interpretations are usually unsatisfying because they frequently involve too strong an element of personal judgment or even intuition and because it is difficult to amass sufficient trustworthy data to substantiate the correlation.

● **Conclusions.** My principal desire in this discussion has been to call your attention to the difficulty of the problems involved in evaluating a proposed geophysical method. I hope I have made it clear that this is a problem which demands the most careful and thoughtful attention. It is a problem that can be solved correctly only by teamwork between geophysicist, geologist, and management. Each must contribute his full share and have his full responsibility. The contact between the members of the team must be intimate and each must have the confidence of the others. This is not a problem which can be solved by the haphazard methods that have been used in the past. Nor is it a problem that can be solved by oratory or debate.

In conclusion, I wish to make it clear that while my topic has called for emphasis on possible new methods, I am neither too optimistic about their possibilities nor too pessimistic concerning the remaining possibilities of our present methods. I expect considerable improvement in our conventional instruments and techniques. But let me close with a word of warning; the future progress of geophysics cannot come entirely from technical advances, either in new methods or improvements of old. Much of it must come from advances in the use of the minds of geophysicists. ★★★

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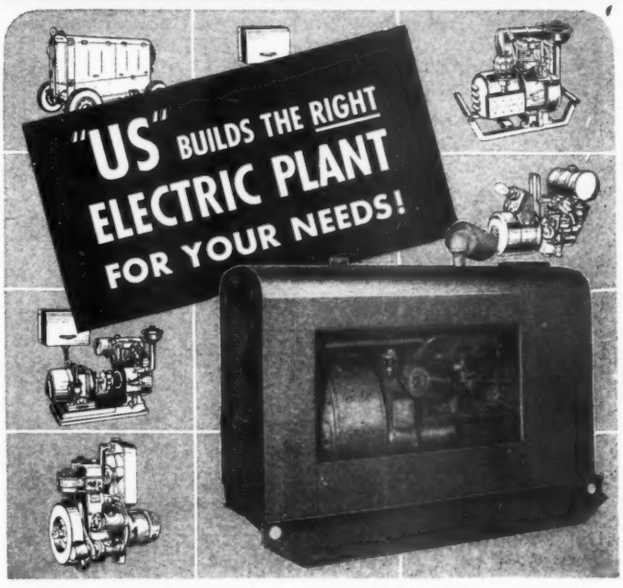

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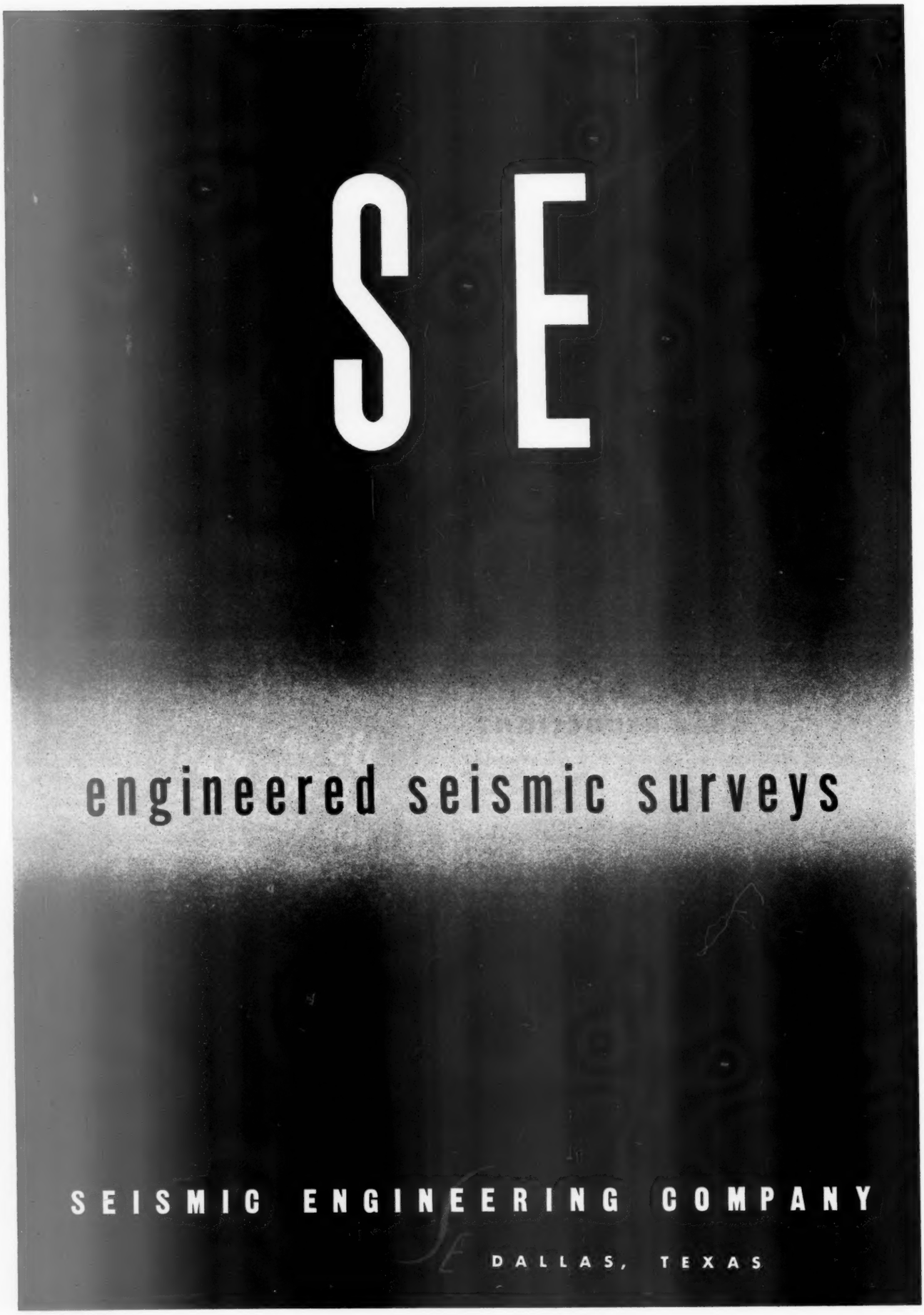
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The Development and Applications of Airborne Magnetometers in the U.S.S.R.*

By A. A. LOGACHEV

Translation by H. E. HAWKES, U. S. Geological Survey

TRANSLATOR'S NOTE: These three papers by A. A. Logachev describe the pioneer work by the Russians in magnetic exploration with airborne equipment. Partly because of the language and partly because of the obscurity of the journals in which it was published, information on this work has not been widely circulated among American geophysicists. It is hoped that these translations will be of historical if not of practical interest to the profession.

Miss Taisia Stadnichenko of the Geological Survey has checked the translations for errors and misinterpretations.

EDITOR'S NOTE: The translations of these three papers are published at this time because of the current interest in the subject and because this early work apparently is very little known to the American geophysical profession (although English abstracts of the papers were published currently in abstract journals.) The figures have been redrawn by tracing enlargements of the originals.

(Paper No. 1)

● **Experimental magnetic survey by airplane.**† The first experimental magnetic survey by airplane was conducted over the Staraya Russa magnetic anomaly between the 19th and 21st of July, 1936. The survey was organized by the Central Geological and Prospecting Institute (TsNIGRI), and carried out by A. A. Logachev, designer of the apparatus, together with A. T. Maiboroda.

The apparatus consisted of an induction coil with a bi-plate collector and brushes on a rotating commutator. It was designed for the measurement of the vertical component of the earth's field.

The rotating coil is driven by an electric motor. The inductor and motor are suspended on gimbals in such a manner that the axis of rotation is always horizontal. The commutator and brushes are adjusted so that commutation of the current occurs at the moment of maximum e.m.f. resulting from the vertical component, and minimum e.m.f. from the horizontal component. A sensitive direct-current galvanometer is shunted into the circuit. When the coil is rotating at high speeds, the galvanometer records only that part of the current which is proportional to the vertical field, as the net current resulting from the horizontal field will be equal to zero.

Measurements are based on the principle of full compensation of the vertical magnetic field. The compensation is made in the following manner. The vertical field of the earth is opposed by fixed magnets whose fields are equivalent to the minimum value of the vertical component which may be expected in the course of the projected survey. The residual field is then compensated by the magnetic field from a current flowing in a fixed coil wound around the body of the instrument. Current in the fixed coil is supplied by constant voltage batteries. A rheostat regulating the current in the fixed coil is connected to a pen which records the resistance of the circuit on a moving tape. In practice, the recorder was actuated by a potentiometer rather than directly by the rheostat. The null-point of the galvanometer indicates complete compensation. This method of measuring the magnetic field is free from errors arising from variations in speed of rotation of the induction coil, as any variations in speed will affect only the accuracy of the instrument.

For the test survey we were offered a two-seated, open-cockpit airplane. Because of weight limitations we were forced to eliminate the recorder, and had to forego a continuous record in favor of visual observations taken every other minute.

The flight was laid out over the northern part of the Staraya Russa magnetic anomaly along a line about 60 km. in length passing from Novgorod to Valdai. According to data gathered by the Bureau of Geomagnetic Surveys, the magnetic intensity along this line ranges from—230 gammas to 1430 gammas.

Results of the survey are presented in the form of three curves (Fig. 1). Curve No. 1 represents a survey at an altitude of 1000 meters. Owing to low clouds ground control was lost at the end of the flight.

Curves No. 2 and 3 represent traverses from Novgorod to Valdai and back at an altitude of 300 meters. For comparison, curve No. 4 shows observations on the ground with Schmidt balances, taken from data published by the Bureau of Geomagnetic Surveys.

The anomaly is shown quite distinctly on all three curves. The notable displacement of the maximum may be the effect of errors in orientation; the divergence in values of the anomaly may be ascribed to instrumental error.

We may conclude as a result of our survey that magnetic anomalies which are greater than 1000 gammas in total intensity may be measured with the airborne instrument of our construction.

July 29, 1936

(Paper No. 2)

● **Magnetic survey by airplane in the Zapadnaya Oblast.**‡ After the experimental survey by airplane over the weak Staraya Russa magnetic anomaly, the

*Published in *Geophysics*, Journal of the Society of Exploration Geophysicists, April, 1946.
†Razvedka Nedr, No. 17, pp. 40-41, 1936.

‡Razvedka Nedr, vol. 7, No. 51, pp. 34-37, 1937.

FIG. 1. Magnetic Curves, Novgorod to Valdai. Curve 1, Altitude 1000 meters; Curves 2 and 3, Altitude 300 meters; Curve 4, traverse on ground with Schmidt balances. Place names: 1. Novgorod, 2. Kholynya, 3. Bolshoe Luchino, 4. Zavod Proletarii, 5. Dorozhno, 6. Krasnye Stanki, 7. Kunkino, 8. Zaitsevo, 9. Lipgora, 10. Viny, 11. Moshka, 12. Dolgii Most, 13. Krestsy.

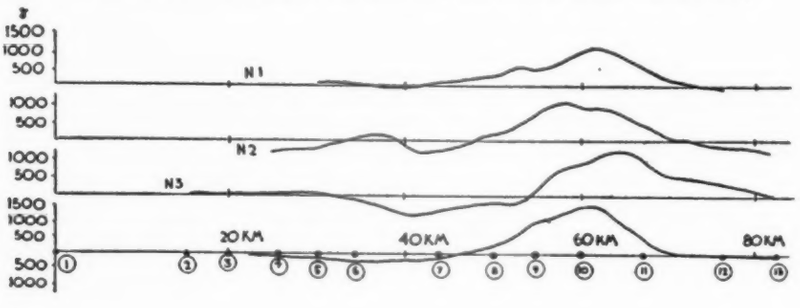
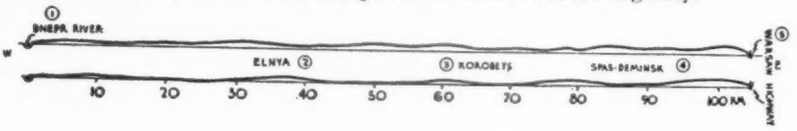


FIG. 2. Two vertical intensity curves recorded by airplane along the Smolensk-Sukhinichi railway between the Dnepr river and the Warsaw highway.



Central Geological and Prospecting Institute (TsNIGRI) organized an experimental aerial survey over the strong anomalies of the order of 30,000 gammas within the limits of the Zapadnaya oblast (Western district). The author was assisted by A. A. Strona, senior engineer of the Institute who laid out the flights, and by I. V. Ryazantsev, airplane mechanic.

The instrument was redesigned and completely rebuilt, with a resulting reduction in mechanical friction and air resistance of the rotating coil. The total weight was 30 kg., as compared with 72 kg. for the previous equipment. It was installed in the airplane at the Smolensk airdrome, which also served as the operating base.

The construction of the new equipment delayed our departure. As a result, the field work was done in late September and early October under extremely unfavorable weather conditions—low clouds, almost constant rain or snow, and relatively strong winds. The airplane was an open-cockpit type, and the cold and precipitation seriously interfered with the work.

Measurements were made over the Baryatinsk and Rognedinsk anomalies, and along a line from Smolensk to Baryatinsk station (about 150 km.). All results are presented in the form of graphs.

Fig. 2 shows vertical intensity curves on two parallel traverses along the Smolensk-Sukhinichi railway, between the Dnepr river on the west and the Warsaw highway on the east. Along this line the magnetic field is known only from scattered observations of absolute intensity. During the flight out from Smolensk (lower curve) we have an apparent normal field as far as Spas-Deminsk; between the latter and the Warsaw highway, an increment in the order of 2000 to 2500 gammas was recorded. The results of the survey beyond the Warsaw highway are shown in Figs. 3 and 4. During the return flight (upper curve) the anomaly in the vicinity of Spas-Deminsk is again recorded, indicating that between the Warsaw highway and Spas-Deminsk the vertical intensity is actually somewhat greater than normal. Further on the route to Smolensk beyond Spas-Deminsk, the vertical intensity again increases by about 1500 gammas and then remains fairly constant as far as the Dnepr. This variation is probably not caused by an actual change in the earth's field, but is more probably due to one of the following two causes: (1) a change in readings resulting from instrumental drift after four hours of steady operation (possibly the effect of a current leak due to dampness, or of a shift in position of the collector brushes); (2) a change in the magnetic field of the motor of the airplane, produced by greater speed on the return trip. An error in the instrument itself seems unlikely, as it was tested repeatedly in the course of the survey and showed no observed change in its behavior. A change in the magnetic field of the motor, however, could very well have accounted for the discrepancies, as the motor was not shielded and

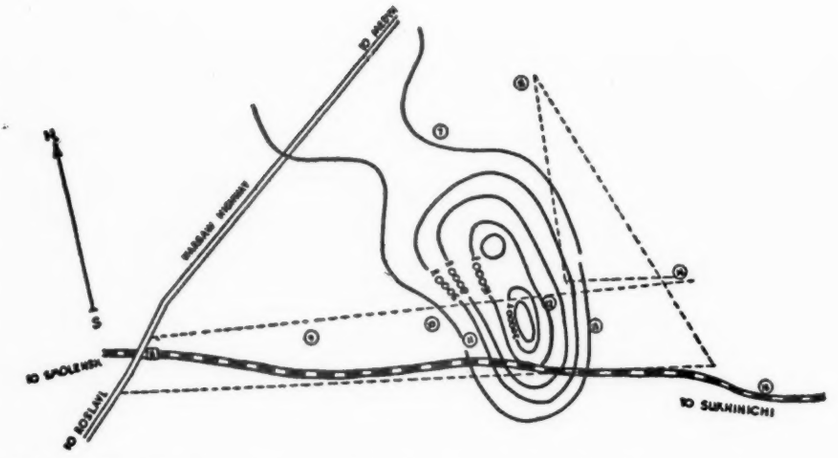


FIG. 3. Vertical intensity contours on the ground over the Baryatinsk magnetic anomaly. Broken lines indicate aerial traverses. See Fig. 4 for scale. Place names: 6. Kholmi, 7. Zimnitsi, 8. Chiplyaevo station, 9. Zanoznaya, 10. Vysokaya Gora, 11. Shemelinki, 12. Shershnevo, 13. Krasnyi Kholm, 14. Butyrki, 15. Kobylye.

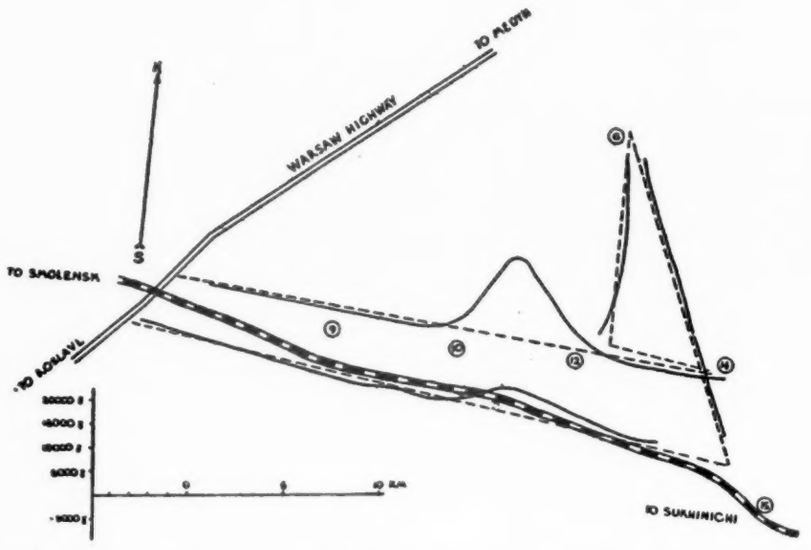
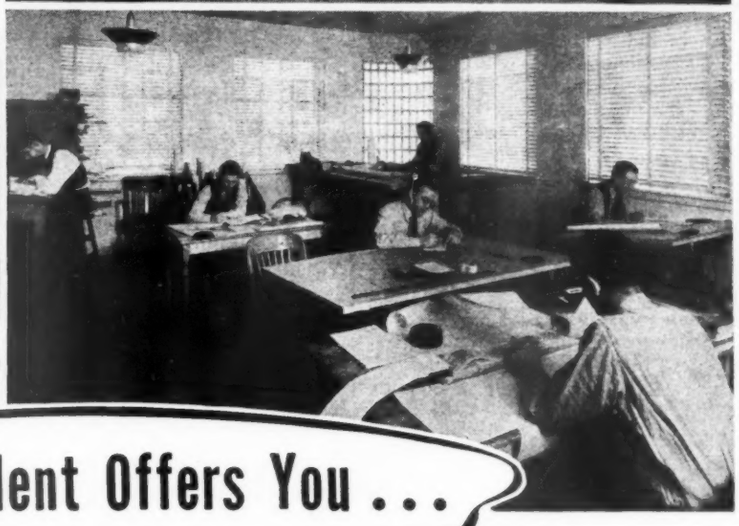


FIG. 4. Vertical intensity curves from the aerial survey over the Baryatinsk anomaly. Place names: 9. Zanoznaya, 10. Vysokaya Gora, 12. Shershnevo, 14. Butyrki, 15. Kobylye.

some observed changes in instrument readings were correlated with changes in r.p.m. This effect was particularly noticeable beyond the Dnepr as we were returning to Smolensk, where the readings again became normal (this part of the curve is not shown in Fig. 2).

Fig. 3 shows the location of flight lines and magnetic contours drawn from surface observations over the Baryatinsk anomaly east of the Warsaw highway. Fig. 4 shows vertical intensity curves along the flight lines. The pilot was instructed to cross the strongest part of the anomaly at different elevations, but low clouds (200 to 300 meters) and strong winds interfered with the plan. At the end of the first traverse the pilot brought the airplane to a point considerably south of where we had planned to come out, indicating that we had crossed only the southern part of the anomaly. After that the location of flight lines was determined in part by occasional glimpses of recognizable landmarks, in part by noting the elapsed time between turns, but chiefly by the anomaly as it was being recorded. Then, by using the map of the magnetic anomaly in conjunction with the instrument readings, we were able to determine our course fairly accurately. Thus in this flight we reversed our problem, and instead of determining magnetic intensity over known terrain we determined our location by instrument readings over known magnetic features. The anomaly has been outlined quite satisfactorily, as may be seen in the illustration.

The Rognedinsk anomaly is located about 130 km. from Smolensk along the Roslavl-Sukhinichi railway between the Oster and Desna rivers. The railway line and the rivers at each end served as ex-



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cellent landmarks. We had planned to cross the anomaly six times at different elevations, starting at 1000 meters and working down. We arrived in the midst of low clouds and rain which prevented us from taking observations at this elevation. The clouds were continually shifting and the pilot, who was anxious to gain altitude, did not hold the plane at a constant level during any one traverse. Thus, all six curves were recorded at a variable elevation ranging from 200 to 300 meters. Curve No. 1 (reading from bottom to top in Fig. 5) was recorded at an elevation of about 300 meters. No. 2 was below 200 meters; the compensating field in the fixed coil was not sufficient to record the maximum anomaly, and the curve was interrupted while the instrument was adjusted for greater compensation. No. 3 was recorded at an elevation somewhat greater than 200 meters. No. 4 started at an elevation above 300 meters, but over the anomaly itself the airplane was descending because of the appearance of low clouds. No. 5 was at 300 meters and No. 6 at 200 meters.

The altimeter was read by the pilot who communicated the information to the operator. The accuracy of these data is not great. In any further work it will be necessary to provide the operator with an altimeter. In this connection, attention should be drawn to the fact that at a distance of about 25 km from Desna all the curves show small increments in vertical intensity which are greater at lower elevations. Evidently we have here a weak anomaly.

Discrepancies in maximum values of vertical intensity may be explained by the variable elevation of the flights. If the elevation were known more accurately, the maximum values could be used in calculating the depth to the center of the magnetic body. As may be seen in the diagram, discrepancies in the horizontal position of the curves are negligible, as a result of the accurate orientation made possible by the railway line and the rivers. The accuracy with which the anomalies were located may be seen in the diagram.

Disregarding the unexplained changes in vertical intensity observed on the traverses between Smolensk and the Warsaw highway, we find that the accuracy of our survey in the Zapadnaya oblast was approximately 1000 gammas. It should be borne in mind that the work was carried out under extremely unfavorable weather conditions.

The results of this project once more prove the feasibility of magnetic surveys by airplane. The accuracy of measurements will depend to a large extent on weather conditions. Our results indicate that anomalies greater than 2000 gammas can be measured in any weather in which it is possible to fly. In calm and clear weather anomalies of quite low intensity can be measured, as was found in our flights over the Staraya Russa anomaly when even less sensitive equipment was used.

The use of aerial magnetic survey in geological exploration will permit a wider application of magnetic methods not only in the search for magnetic orebodies, but in the study of regional geology as well. Surveys at different elevations provide new data which may prove to be extremely valuable in computing the depth to the center of a magnetic body. It should be realized that aerial surveys would be particularly important in the study of regional anomalies, as anomalies arising from superficial magnetic masses of no regional significance will tend to fade out with increased elevation. Finally, an obvious advantage of aerial magnetic surveys is the speed with which large and inaccessible areas may be investigated—a speed unprecedented in any previous geophysical work.

(Paper No. 3)

● **An experimental application of the aeromagnetic survey to the determination of depths in magnetic masses.**** In 1937 the Central Geological and Prospecting Institute (TsNIGRI) conducted an experimental magnetic survey of the Kursk magnetic anomaly near the town of Staryi Oskol.[1]

The work was done by the author together with A. I. Garnov, engineer of the Institute, and A. I. Dyukov, engineer of the Geological Exploration Trust for the Kursk magnetic anomaly.

One of the unsolved problems was to determine whether the depths of the upper and lower limits of the Kursk ferrous quartzites could be computed from aeromagnetic data. The depth of the upper limit of the body was known sufficiently well from underground development, but no trustworthy data existed concerning the lower limits.

**Materialy, Tsentral'nogo Nauchno-Issledovatel'skogo Geologo-Razvedochnogo Instituta, Geofizika, Sbornik 8 (Also English title: Materials of the Central Geological and Prospecting Institute, Geophysics, Fascicle 8) pp. 35-38, 1940.

[1]Raboty po magnitnoi s'emke s samolet. kratki izlozhennye avtorom v zhurnale: (Work on magnetic surveying by airplane, briefly summarized by the author in the journal): Razvedka Nedr No. 17, 1936 and No. 5, 1937.

FIG. 5. Vertical intensity curves observed from the air along the Roslavl-Sukhinichi railway between the Oster and Desna rivers (Rognedinsk anomaly). Elevations of flights, Curve 1, 300 meters, Curve 2, below 200 m.; Curve 3, above 200 m.; Curve 4, start at 300 m.; lower over anomaly; Curve 5, 300 m.; Curve 6, 200 m.

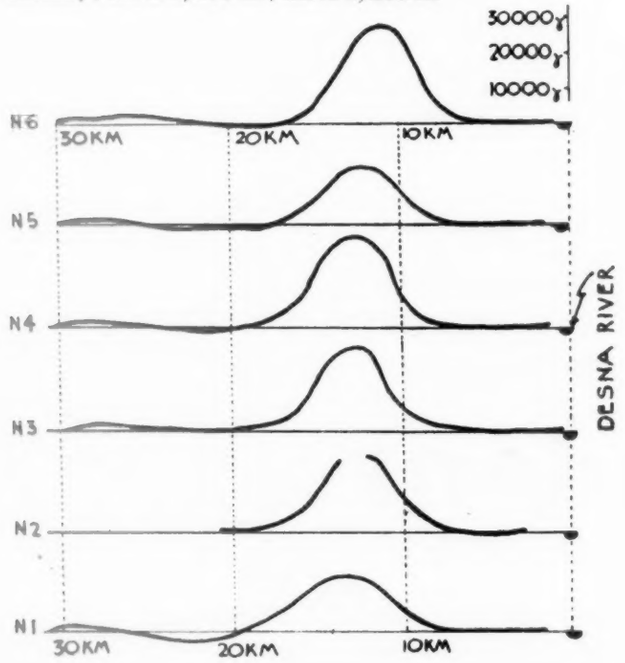
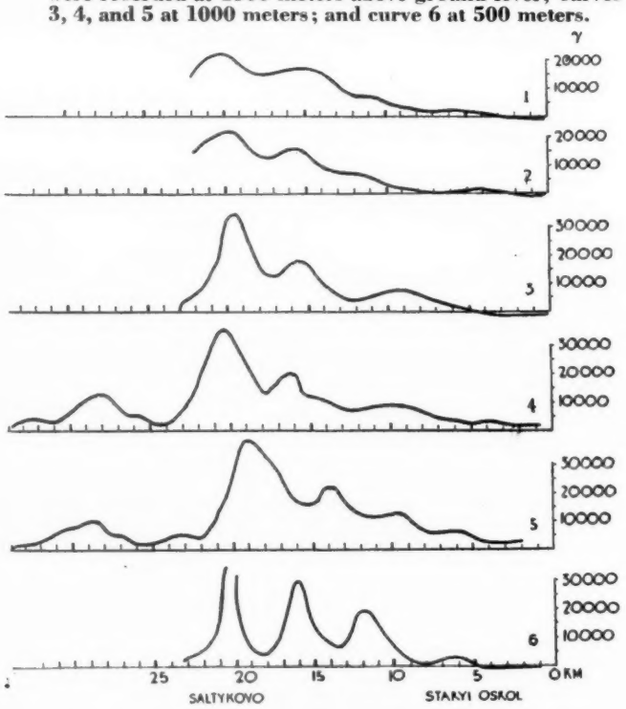


FIG. 6. The Kursk magnetic anomaly in the Staryi Oskol area. Vertical intensity curves along a traverse through Staryi Oskol, Saltykovo, and Kladovoe. Curves 1 and 2 were recorded at 1500 meters above ground level; curves 3, 4, and 5 at 1000 meters; and curve 6 at 500 meters.



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Four traverse lines were laid out approximately at right angles to the strike of the quartzites. A total of 22 traverses were run at elevations from 500 to 1600 meters. Five of these were rejected for various reasons (lack of experience on the part of the observer appears to be the ultimate cause in every case); the remainder of the curves were used in solving the problem at hand.

For the problem which we are considering in the present article, we make use of curves recorded between Staryi Oskol and Saltykovo over the most intense part of the anomaly.[2] Z_a measured on the surface reaches a maximum of 1.4 gauss; the depth of the ferrous quartzites below the surface is approximately 150 meters. The quartzites form a series of steeply-dipping beds several hundred meters thick and several scores of kilometers along the strike. With these dimensions at elevations of 1000 meters and more, the magnetic body may be approximated by a double line of magnetic poles, where the separation of the pole-lines is finite.[3] For this case the maximum is expressed by the formula:

$$Z_a = 2\sigma\left(\frac{1}{r-l}-\frac{1}{r+l}\right)= 2\cdot\frac{2\sigma l}{r^2-l^2} \quad (1)$$

where σ is the linear density of magnetism, $2l$ the distance between the linear poles, and r the vertical distance from the surface of observation to the center of the layer. If we take σ, $2l$ and r as unknowns, we need at least three equations for finding the values of these unknowns. The data from surface surveys cannot be used, as the concept of linear poles becomes invalid where the plane of observation is so close to the upper edge of the quartzite. We use two profiles at an elevation of 1500 meters, where the observed maxima are 0.22 and 0.225 gauss; and three profiles at an elevation of 1000 meters with observed maxima of 0.35, 0.355, and 0.385 gauss.

We can rearrange equation (1) as follows:

$$Z_a\,[(r_0+a)^2-l^2] = 4\sigma l \quad (2)$$

where r is the vertical distance of the center of the layer below the ground surface, and a is the elevation of the flight above the ground surface. From this we find the approximate values: $r_0 = 1000$ m., $l = 800$ m., $4\sigma = 1500$ (in absolute units $4\sigma = 1.5 \times 10^5$). By the method of least squares we derive a correction for the approximate values of and r_0 when l has a set value, such that $r_0 = 1190$ m., and $l = 940$ m.

It is now possible to find a new value: $4\sigma = 1540$, corresponding to corrected values for r_0 and l. Inserting the new value for 4σ, we find: $r_0 = 1040$ m., and $l = 830$ m. These results show that the depth to the upper line of poles lies between 200 and 250 meters, and the depth to the lower line of poles between 1900 and 2100 meters; the distance between them is therefore between 1700 and 1900 meters. The actual dimensions of the ore-body may be somewhat greater, as the line of poles will not coincide exactly with the limits of the ore. Leist[4] in his computations uses the law adopted by the Swedish magnetologists, who assume that the distance between the poles is equal to 0.9 times the vertical extent. If we apply this ratio, we obtain the following values for the dimension in question: distance to the upper limit ranges from 100 to 150 meters, and the vertical distance to the lower limit ranges from 2000 to 2100 meters. The known distance to the upper limit is 150 meters. The degree of coincidence of the actual distance with computed values for the distance to the upper limit of the quartzite will also characterize the precision of determination of the lower limit.

We shall now solve the problem of the depth of the lower limit using the known distance of the upper limit (150 meters). Inasmuch as the formula gives only the depth of the line of poles, which generally does not coincide with the upper limit, it is necessary to make an assumption regarding the probable distance between the limit of the body and the line of poles. For solution of this problem let us assume three possible distances between the limit and the linear poles: 0, 50, and 100 meters. Then we obtain:

Distance between upper limit and pole-line, in meters		Vertical distance to lower limit	4σ
0	1300	2750	1200
50	1030	2310	1400
100	850	2050	1580

The first assumption should be discarded, as it is scarcely likely that the line of poles will coincide with the upper limit of the magnetic body where the horizontal dimensions of the body are so large compared with the vertical.

On the basis of the two other assumptions, the lower boundary has been determined at 2050 and 2310 meters. More exact calculations are not warranted on the basis of vertical intensity measurements from an airplane. It is possible to estimate the accuracy of the various measurements as roughly $\pm 1000\gamma$; an average value of Z_a as used in the computations naturally will be somewhat more acurate. Granting the possibility of an error of $\pm 1000\gamma$, we solve the problem with a modified value, $Z_a = 0.23$ and 0.35 (in place of 0.222 and 0.363); then $l = 1400$ m., and the depth to the upper pole line becomes 460 meters. When $Z_a = 0.21$ and 0.37, $l = 670$ m., and the depth to the upper pole is 100 meters. The second solution drops out, as it is obviously not possible for the depth of the upper pole to be less than 150 meters. The first solution indicates that the ratio of $2l$ to the vertical dimension of the bed is about 4:5, which holds true for relatively short magnets. The latter consideration in itself does not force us to discard the solution. Another consideration, however, that does apear to invalidate our solution is the fact that the graphic determination of the upper linear pole

[2] Atlas kart elementov zemnogo magnetisma (Atlas of maps showing the elements of terrestrial magnetism): Vyp. X, trudy OKKMA, Promizdat 1927.

[3] Bauman, V. I., Interpretataiya resul'tatov magnitnoi s'emki (Interpretation of the results of magnetic surveys): Bitor 1932 (steklografiya).

[4] Leist, E. E., Kurskaya magnitnaya anomaliya (Kursk magnetic anomaly): 1921.

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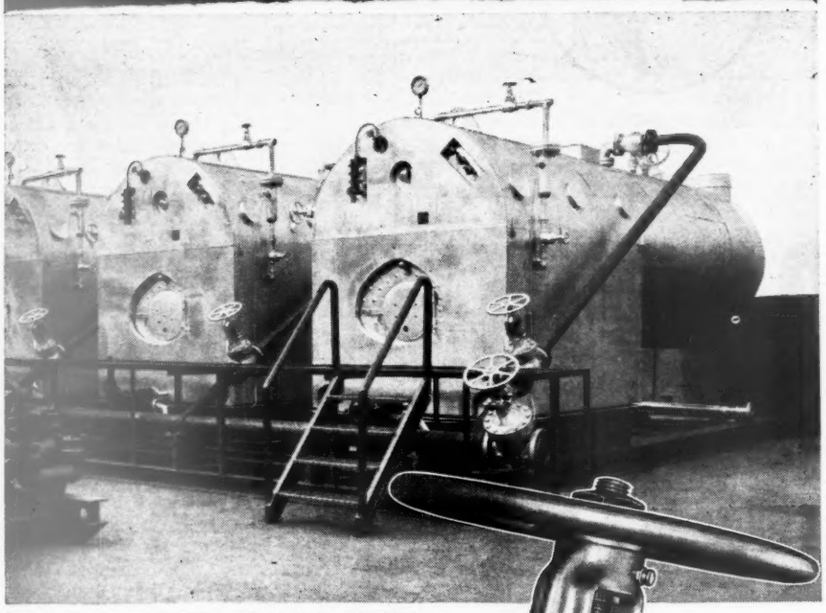

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from the data of surface surveys shows that the depth of the upper pole line is in the order of 200 meters.[4]

Thus a solution of the problem based on extreme values of Z_a, as described above, leads to incorrect results. This indicates that the data from our original calculations are sufficiently reliable, and that the value (2000 to 2300 meters) for the distance to the lower limit of the quartzites is valid.

For our solution of the problem we have manipulated the value of 4σ. The most satisfactory solution seems to be where $4\sigma = 1500$, or $4\sigma = 1.5 \times 10^5$ CGS units. This value is equal to the density of magnetism in a strip one centimeter wide measured across the strike of the bed. If we assume that the magnetic susceptibility k of the quartzites is equal to 1 CGS unit, then $\sigma = 0.5$ CGS units per cm². Using this in conjunction with values found from our equations, we determine the width of the beds at 750 meters. However, the value $k = 1$ does not fit the facts; only rarely does k attain the value of 0.5, and usually it is considerably smaller.[5] On the other hand, the intensity of the anomaly in the areas examined is undoubtedly due to a large extent to the effect of residual magnetism,[6] the magnitude of which must be several times 0.5 CGS units per cm³ in order to account for the observed intensity of the anomaly.

We have recently undertaken the measurement of residual magnetism.[7] Unfortunately we had no samples of the ferrous quartzites from the Kursk magnetic anomaly, and consequently we were not able to make a more detailed analysis of the value of σ.

Calculations of the lower boundary of the Kursk ferrous quartzites using the data of surface surveys have been reported by M. V. Yuneev[8] and V. A. Kostitsin.[9] In their calculations, both workers have applied the theory of the magnetic field around elliptical cylinders. Kostitsin has assumed the equivalence of a single cylinder; Yuneev, on the other hand, has employed collections of cylinders to approximate the quartzite beds, adjusting the positions of the cylinders to correspond with individual beds. According to Kostitsin the distance to the lower limit is six to seven kilometers, whereas according to Yuneev it is only two to three kilometers.

The results of our calculations correspond closely with Yuneev's results; our method, however, is distinguished by its extreme simplicity.

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[4]Reikh, Geologicheskye osnovy prikladnoi geofiziky (Geological principles of applied geophysics): Prikladnaya geofizika, vyp. 1, 1936.

[5]Ivanovski, B. M., O variatsiyakh elementov zemnogo magnetizma v anomalnom pole (On variations of the elements of the earth's magnetism in anomalous fields): Inf. sbornik po zemnomu magnetizmu i elektr. No. 4, 1937.

[6]Logachev, A. A., Izmereniya magnitnykh svoistv gornykh porod (measurements of the magnetic properties of rocks): Inf. sbornik po zemnomu magnitismu No. 4, 1937.

[7]Yuneev M. V., Magnitorazvedka v KMA (Magnetic exploration at the Kursk magnetic anomaly): Fondy TsNIGRI, 1935.

[8]Kostitsin, V. A., Metody opredeleniya polozheniya magnitnykh mass (Methods of determining the location of magnetic masses): Trudy OKKMA, vyp. 1924. ★★★

Simplicity and Flexibility of Thermofor Catalytic Cracking†

By **H. D. NOLL**, Houdry Process Corporation
E. V. BERGSTROM, Socony-Vacuum Oil Company, and
K. G. HOLDOM, Houdry Process Corporation

A small scale integral TCC unit has been developed by engineers of Houdry Process Corporation and Socony-Vacuum Oil Company, Inc. The unit can be designed to process from 1000 bbl. per stream day upward of virgin charging stocks ranging from heavy naphthas to vacuum distillates. Its simplicity of design and flexibility of operation make catalytic cracking feasible and practical for operators of smaller refineries. The unit is characterized by high yields of high quality product at high liquid recoveries with low investment cost and low operating and maintenance costs. The integral design and simplicity of construction details make for a high percentage of on-stream time.

One outstanding and generally recognized feature of the TCC process is the high yield of useful products per unit of feed disappearance and per unit of catalyst deposit. Liquid recoveries (gasoline plus butanes plus cycle gas oil) range from 97 to well over 100 per cent depending upon the character of the charging stock and the conversion employed. These high liquid recoveries are obtained by operating at conditions where catalytic action can be maintained at a maximum and deleterious thermal side reactions kept to a minimum. These operating conditions require the maintenance of relatively high catalyst activity and, for very high conversions, recycling of catalytic gas oil.

As a result of careful control of regeneration conditions the catalyst activity in TCC units is maintained at a high level. The thermofor kiln regenerates in stages or zones each having its own air and coolant control. The portion of the catalyst deposit containing high concentrations of material other than pure carbon is removed in the initial stages at low temperature conditions (875-975°F.). Thus, water vapor and oxides of impurities such as sulphur are removed from the regeneration process before any high temperature combustion occurs. It then becomes possible to reactivate the catalyst fully by burning off carbon to a very low residual concentration on catalyst without incurring losses in activity from high temperature contact with steam or sulphur compounds. This stage burning allows high catalyst activity maintenance with relatively low catalyst replacement rates. Performance on commercial units throughout the war program has demonstrated the practicability of maintaining activities of 30-31 A.I. for clay with 0.5-0.6 lb. per bbl. make-up and 34-36 A.I. for synthetic catalyst with 0.15 to 0.27 lb. per bbl. make-up.

Curves of equilibrium activity index vs. catalyst make-up rate are shown in Figs. 1 and 2.

Table I has been prepared from correlations to illustrate the effect of catalyst activity on gasoline yield, liquid recovery, and coke production at constant gas oil disappearance.

It will be noted that with the lower catalyst activity the coke plus dry gas yield has increased by 1.2 per cent, whereas the gasoline yield and liquid recovery have decreased by 2.4 per cent and 1.7 per cent, respectively.

In many instances and especially in the case of installation in smaller refineries recycle thermofor catalytic cracking is particularly attractive. Only moderate recycle ratios are required to produce gasoline yields far beyond the reach of thermal processing methods. The quality of such gasoline is as good as or better than that produced by single pass operation and the increase in investment cost is minor in relation to the substantial gasoline yield increase. In many cases this type of operation can be readily fitted into existing thermal cracking equipment at a considerable saving in investment cost. Table 2 shows yields for single pass operation and for recycling at 0.5/1 and 1.0/1.0 (recycle/fresh feed) ratios on a typical Mid-Continent wide cut gas oil using 30 A.I. clay catalyst.

TABLE 1

Catalyst activity index	28	32
Conversion	60.0	60.0
Temperature	860	860
Gasoline, vol. per cent	46.0	48.4
Liquid recovery, vol. per cent	99.2	100.9
Coke, weight per cent	4.0	3.6
Dry gas, weight per cent	7.6	6.8

TABLE 2

Recycle/fresh feed ratio	0/1	0.5/1.0	1.0/1.0
Debutanized motor gasoline, vol. per cent	42.0	56.0	64.8
Total B-B, vol. per cent	10.0	12.8	15.3
Cycle gas oil, vol. per cent	46.0	28.0	15.0
Dry gas, wt. per cent	6.5	8.0	9.6

†Presented before Western Refiners Association, Fort Worth, Texas, March 27, 1946.

● **Mechanical features.** The main components of the catalytic section of a TCC unit consist of the reactor where oil vapors are contacted with hot catalyst, the kiln where the resulting carbonaceous deposit is burned off and the catalyst regenerated, and bucket elevators to transfer catalyst from the bottom of the kiln to the top of the reactor and from the bottom of the reactor to the top of the kiln. Auxiliary equipment includes a compressor to supply inert gases for sealing the top of the reactor from atmosphere, an air blower and line burner for supplying combustion air to the kiln, and a steam generating system in which water is pumped through the kiln cooling coils after which the steam generated is disengaged in a flash drum; an elutriator the purpose of which is to control the particle size of the catalyst being circulated; a fresh catalyst make-

FIG. 1. Thermofor catalytic cracking.

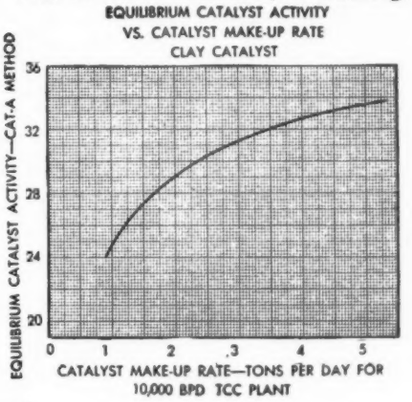
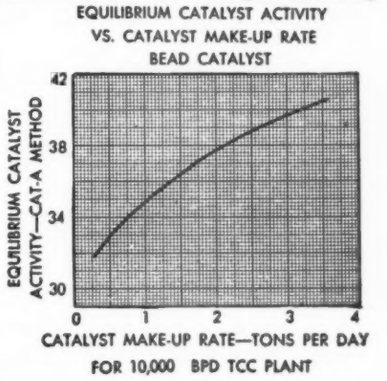


FIG. 2. Thermofor catalytic cracking.



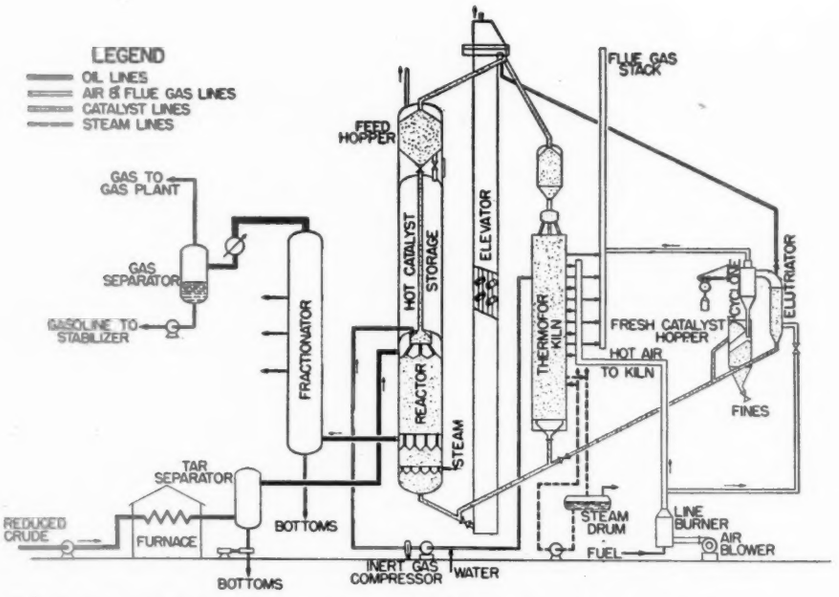


FIG. 3. Simplified flow diagram—typical TCC installation catalytic section.

up hopper and facilities for supplying fresh catalyst to the hopper, and a fines storage bin. This equipment is all of simple and rugged construction.

A characteristic feature of the catalyist flow in a TCC unit is the low catalyst velocities required to circulate the relatively low tonnage of catalyst per hour. The vertical downward velocity of the catalyst in the kiln and reactor is of the order of 6 in. to 12 in. per min. The velocities in the catalyst carrying lines are in the range of 1 ft. to 2 ft. per sec. No erosion has been encountered in plants of the latest design. In the kilns of early installations, some erosion of the refractory kiln lining was experienced. This was corrected by application of hard face refractory coatings and on later installations by the use of suspended refractory brick walls. Inspection indicates that kiln linings of the latter type will have an indefinite life.

No erosion whatever has been experienced in vertical catalyst pipes, but on sloping lines the bottom of the pipe as originally designed eroded out quite rapidly. This erosion was completely eliminated by installing small vertical baffles at intervals in the bottoms of the lines so that a layer of stagnant catalyst remained in the bottom of the pipe and the moving catalyst flowed over this stationary catalyst instead of over the bottom of the pipe. Largely because of the extremely low catalyst velocities employed, erosion in TCC units proved to be a simple and easily corrected problem and may be considered at the present time to be completely eliminated.

Catalyst is supplied to the reactor through a vertical pipe approximately 50 ft. in height depending upon the pressure to be maintained within the reactor. This pipe called the seal leg has a hopper at the top end into which the elevator discharges. This hopper is maintained full of catalyst so that the seal leg also remains full of catalyst at all times. It is therefore possible to operate the reactor at a pressure as high as 15 lb. per sq. in. with the upper end of the seal leg open to atmosphere with catalyst flowing downward through the seal leg against the higher pressure below and without discharging oil vapor to atmosphere, by virtue of the effect of the dead weight of the column of descending catalyst together with the fact that sealing gas flows upward through the catalyst instead of oil vapor. This is done by injecting at the lower end of the seal leg a stream of inert gas a small part of which descends into the reactor and emerges with the product oil vapors, and the balance flowing up the seal leg at a rate sufficient to cause a pressure drop equivalent to the pressure differential between the top of the reactor and atmosphere. The seal leg

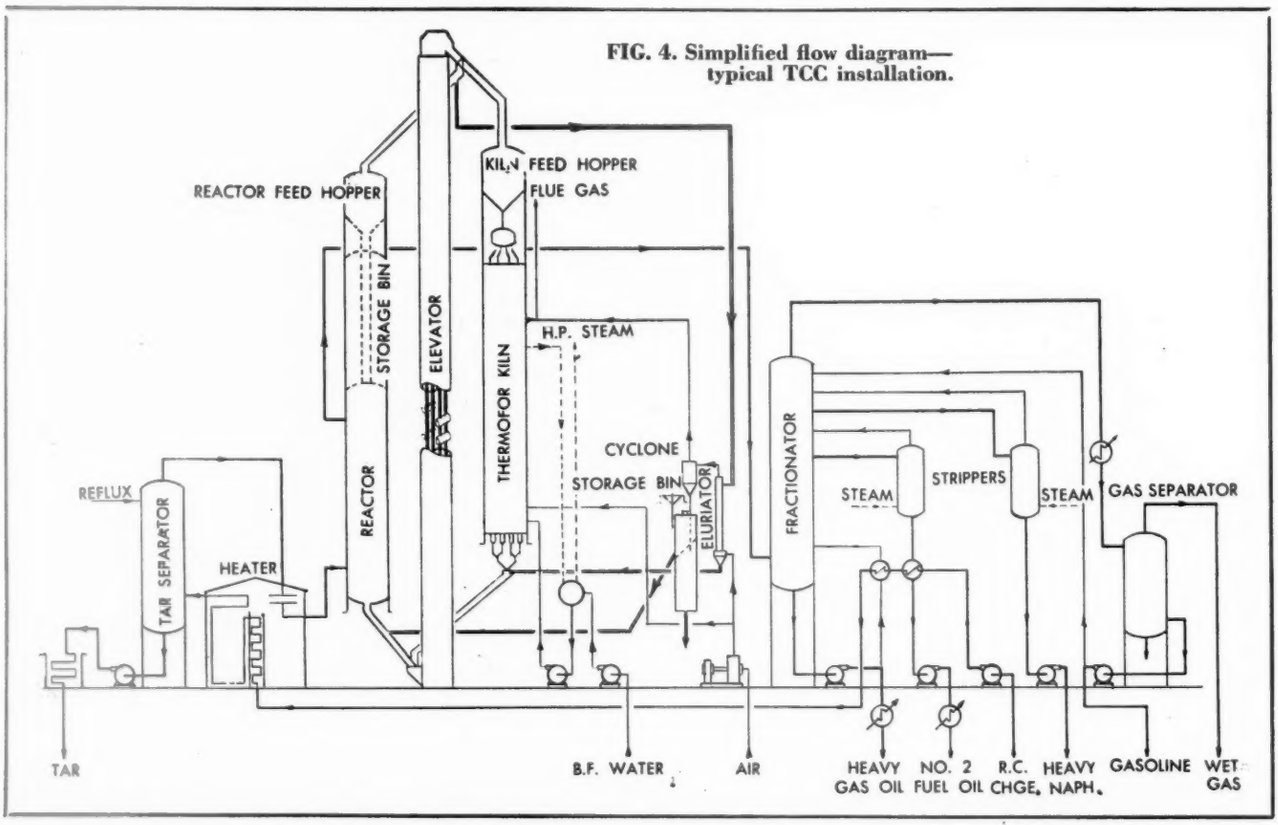


FIG. 4. Simplified flow diagram—typical TCC installation.

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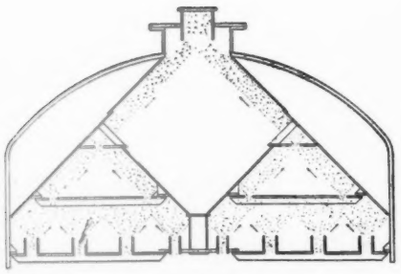


FIG. 5. Typical reactor draw-off baffles.

has proved an extremely simple and foolproof means for introducing catalyst from atmospheric pressure into the higher pressure of the reactor. There is no possibility of blowing a charge of catalyst from the reactor with this arrangement.

The kiln operates under a pressure not more than 1 lb. per sq. in. above atmospheric and usually less and is therefore an inherently safe piece of equipment. The bucket elevators are vented to atmosphere. These atmospheric vents provide a positive separation of the kiln and the reactor and reliance need not be placed on differential pressure valves or such devices to insure that hydrocarbon vapors from the reactor will not enter the combustion zone of the catalytic unit.

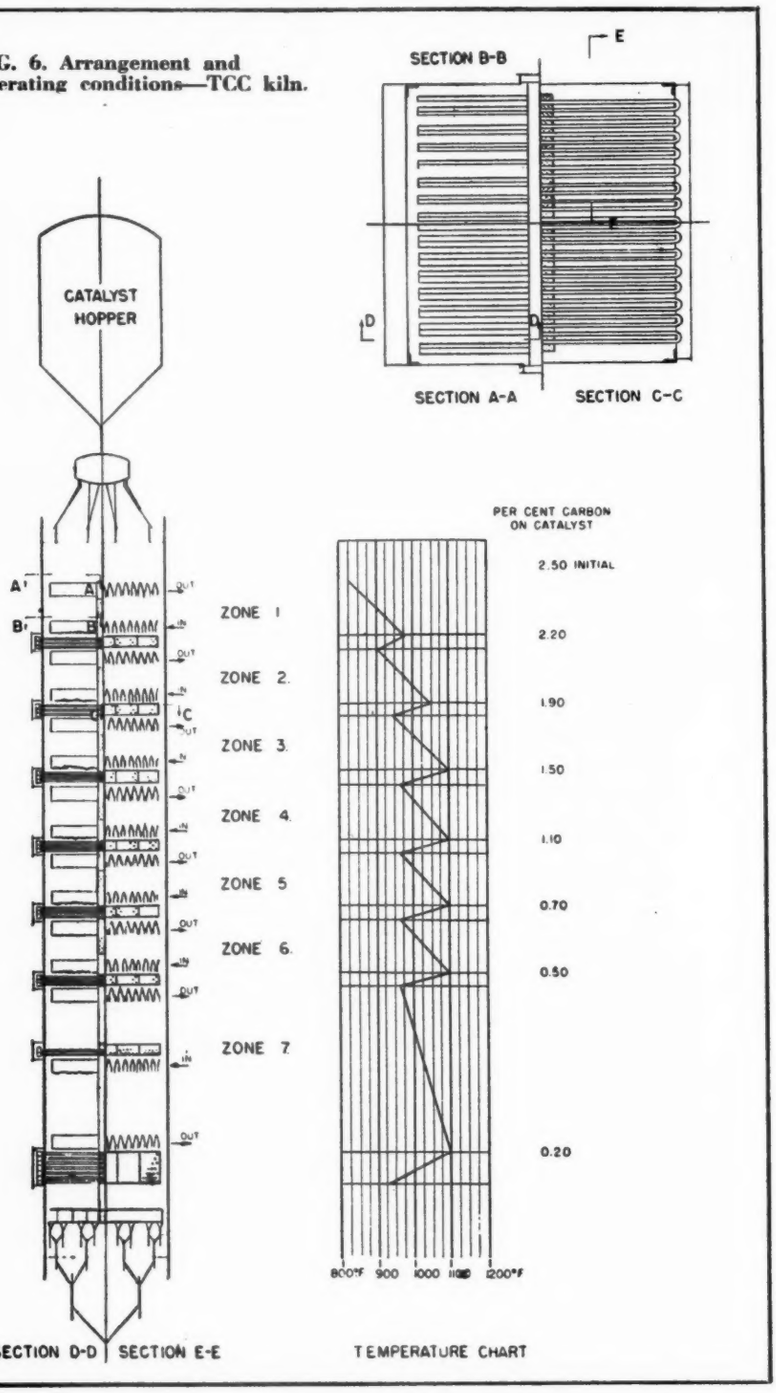
When the first TCC unit was built there was some question of whether bucket elevators would give continuous service at the high temperatures and loads to which they would be subjected in a TCC operation. A 500 bbl. per day pilot plant had been built and operated for a year using a common commercial type bucket elevator and water cooling the head shafts. Only minor troubles were encountered with the malleable iron chain links in this equipment. The TCC elevators now manufactured by the Jeffry Elevator Company have been designed for high temperature operation utilizing the best materials and metallurgical knowledge available. Consequently, even the first units built anticipate a satisfactory chain life of 18 months to 2 years. In the early installations the top chain sprocket teeth wore quite rapidly due to uneven application of hard surface material during manufacture. Despite this it has been possible to obtain from a set of sprockets a life of 12 months or more by simply reversing the teeth. The most recent elevator improvement has been complete elimination of sprockets, substituting a traction drive between the chain and traction wheels. In this manner wear has been distributed around the periphery of the traction rim instead of being concentrated locally at the sprocket teeth and latest wear measurements indicate the anticipated life to be 5 to 10 years for a set of traction rims.

Elevator circulating capacities used have been 100 tons per hr. and 150 tons per hr. with chain speeds in the range of 90 to 125 ft. per min. At this circulating rate and speed, the power required to circulate catalyst is about 60-80 hp. No shutdown due to failure of elevator chains or sprockets has ever been necessary on any of the TCC units built to date.

An important feature of the flow of catalyst in the TCC unit is the uniformity of flow on the cross-section in the kiln and the reactor. This is absolutely necessary if uniform reaction conditions are to be maintained in the reactor and uniform combustion conditions are to be maintained in the kiln. This uniformity of flow in a catalyst bed of large area is accomplished by a system of drawoff baffles at the bottom of the reactor and the kiln. A diagram of this is shown in Fig. 5. This catalyst flow control system was developed by Socony-Vacuum research engineers with the aid of full-scale models and is one of the basic features of the TCC technique.

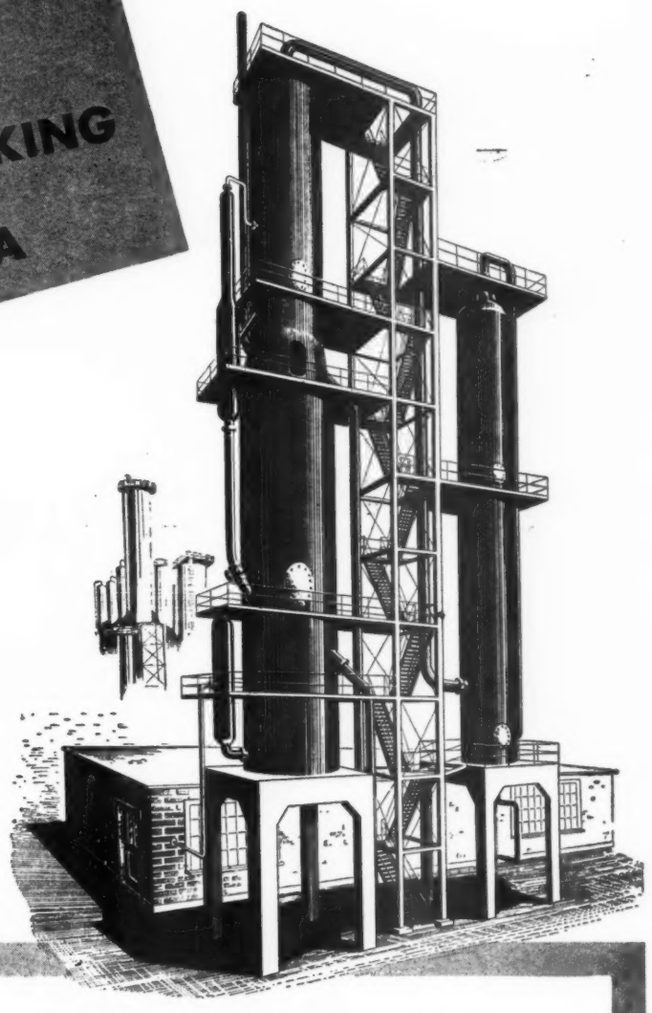
The catalyst flow rate through the kiln and the reactor is controlled by valves in the feed lines to the elevators. The latest type of valve provides close control of the catalyst flow rate and is of very simple and rugged construction. In other locations for shut-off purposes, plug valves are used where some pressure is to be held, and elsewhere just a simple slide plate between flanges is used. The catalyst level in the top of the feed hopper above the reactor is determined by a level indicator that on some units is connected with the catalyst flow control valve in the feed line to the elevator in such a way that automatic

FIG. 6. Arrangement and operating conditions—TCC kiln.



THE UOP *Improved*
FLUID CATALYTIC CRACKING
UNIT PROVIDES A

Continuous Process



The fluid principle, as embodied in the UOP Improved Fluid Catalytic Cracking Unit, provides a truly continuous process.

This unit, while modified in design and construction, retains the basic principles of fluid catalytic cracking which have proven so successful in existing fluid units.

Not only is the initial cost lower, but operating and maintenance costs are reduced to a minimum while efficiency is materially improved.

These facts are important—particularly to the smaller refiner interested in improving his product and reducing his costs. We shall be glad to supply full details regarding the UOP Improved Fluid Catalytic Cracking Unit and discuss its application to specific requirements.

UNIVERSAL OIL PRODUCTS COMPANY

General Offices: 310 S. MICHIGAN AVE. UOP CHICAGO 4, ILLINOIS, U. S. A.

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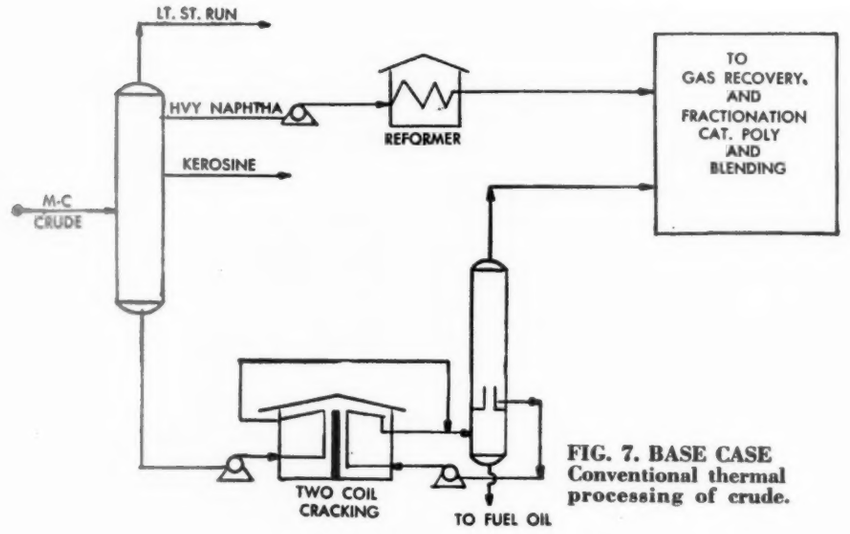


FIG. 7. BASE CASE
Conventional thermal processing of crude.

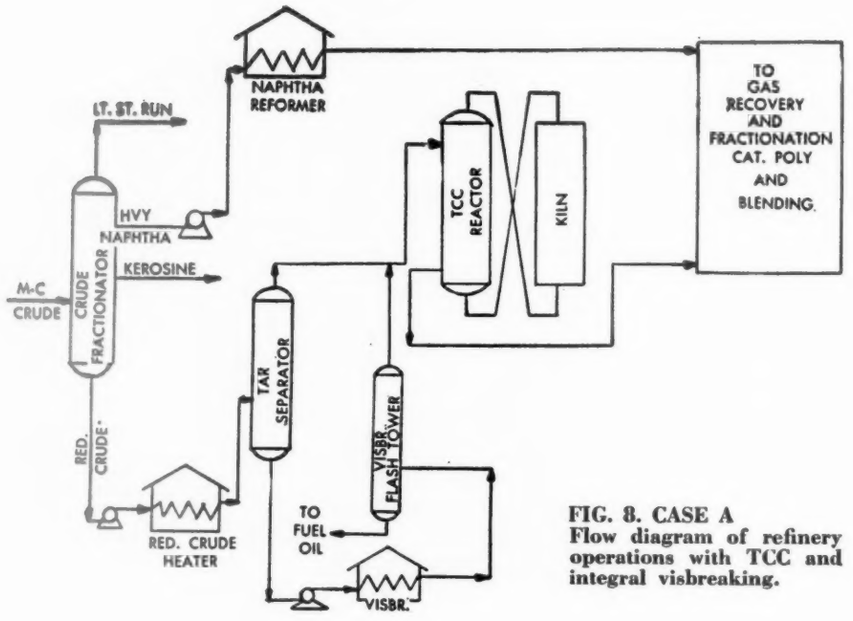


FIG. 8. CASE A
Flow diagram of refinery operations with TCC and integral visbreaking.

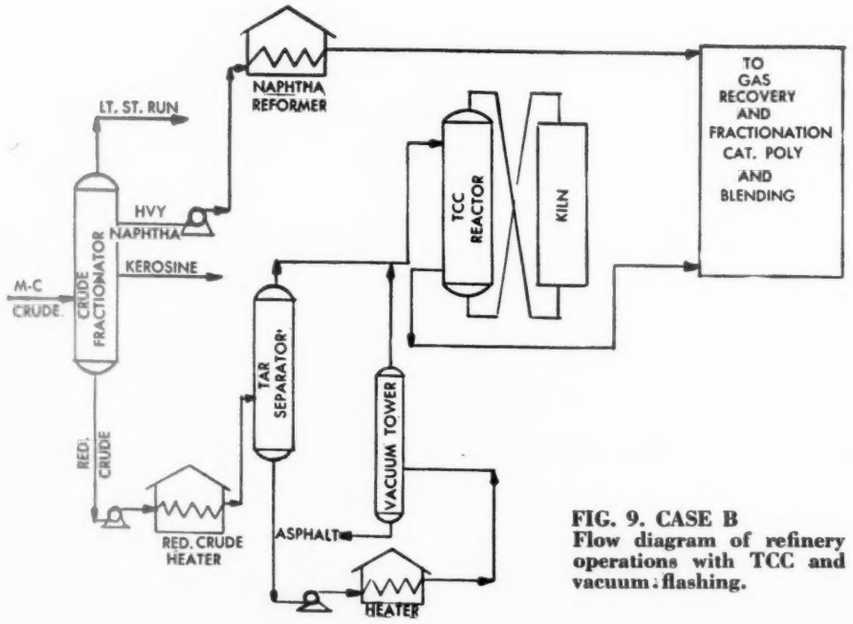


FIG. 9. CASE B
Flow diagram of refinery operations with TCC and vacuum flashing.

level control is obtained. The importance of this interconnection is questionable, however, as feed hopper level stability is easily maintained with only minor adjustments at infrequent intervals at the catalyst flow valves. When the levels in the hoppers become low make-up catalyst is added. Make-up catalyst enters the system from a catalyst make-up hopper that drains into the feed line to one of the elevators.

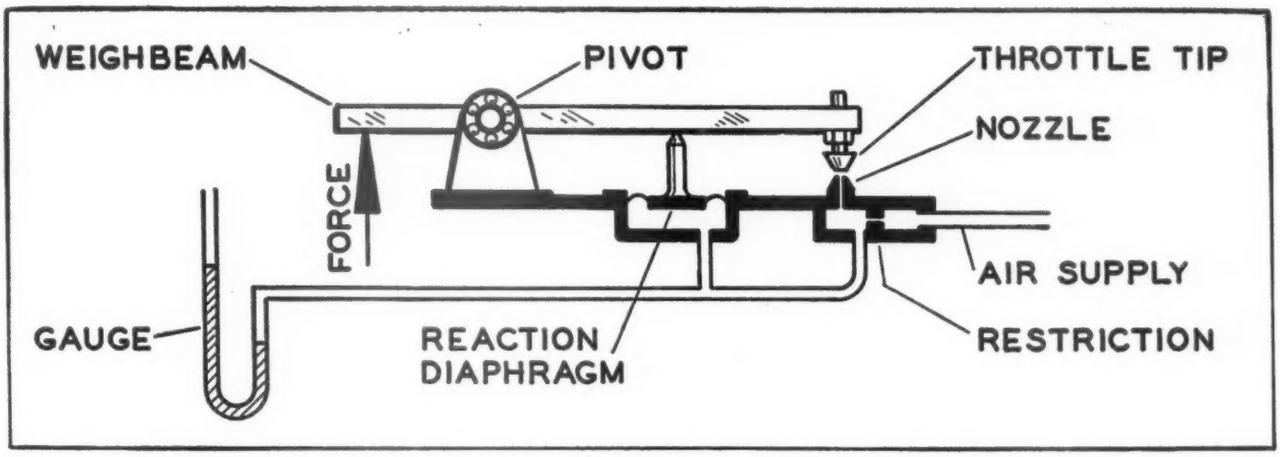
With its low circulating rates and catalyst velocities, and its relatively small forces and power required in circulation of catalyst, the TCC unit utilizes a catalyst moving system that is inherently both safe and simple.

TCC reactors up to the present time have been operated with hydrocarbon vapors flowing countercurrently to the descending flow of catalyst, but the flow in this respect may be either countercurrent or concurrent and the choice is a matter of operating conditions desired in any particular plant. In either system the catalyst bed remains a solid bed with the vapor flowing beween the catalyst particles, which remain in contact with each other and not in agitation in any manner. As a result hydrocarbon vapors are easily disengaged from the catalyst and only a small amount of dust (100-200 lb. per day) is carried into the fractionating tower where it is usually withdrawn with a simple settling pot from which dust and cold oil are discharged at infrequent intervals. Due to this extremely low catalyst carryover no recirculation is necessary to return the catalyst to the system.

A TCC unit is put on stream by circulating catalyst through the kiln and the reactor with the bucket elevators, the catalyst meanwhile being brought up to temperature by supplying preheated air to the kiln. When the proper temperature of catalyst has been reached the reactor charge stream that has been flowing through a bypass around the reactor is cut in slowly by means of motor-operated valves to the reactor, after which the bypass valve is closed and the unit is on stream. As soon as the hydrocarbon is fed to the reactor coke is deposited on the catalyst. The tar separator during the startup period is operated to produce a reactor charge of lighter gravity than the normal charge so as to lay down a reduced amount of carbon initially and enable gradual adjustment of kiln conditions until the unit is fully on stream.

In operating the reactor at constant throughput for a desired product three variables are subject to control. They consist of the catalyst temperature entering the reactor, the catalyst circulation rate, and the vapor temperature entering the reactor. Each one of these variables is subject to simple control and optimum conditions are easily obtained and maintained thereafter. A fourth variable on some units has been the adjustment of space velocity accomplished by changing the catalyst bed depth by means of adjustable feed pipes.

In a TCC kiln with the low catalyst circulating rate used, if all the carbon



The Principle of pneumatic balance transmitters

The Principle of Pneumatic Force-Balance

FOR MEASURING FLOW • PRESSURE • LEVEL • DENSITY • TORQUE

The basic principle of Republic pneumatic transmitters is illustrated above. The force developed by some condition or property of the variable is transmitted by a pivoted weighbeam to the reaction diaphragm. Compressed air, admitted through an orifice, bleeds at the nozzle, being restricted in its flow by the throttle tip mounted on the weighbeam. A very small motion of the throttle tip—less than 0.004" completely opens and closes the nozzle.

As the force produced by the process variable attempts to move the weighbeam, the throttle tip approaches the nozzle. The resulting restriction on the flow of air from the nozzle causes an increase in pressure on the upstream side of the nozzle, which is immediately transmitted to the reaction diaphragm. The force produced by the diaphragm tends to cause the weighbeam to go in the opposite direction. The result is that the throttle tip is held at just the distance from the nozzle which causes stable balance of forces.

Since the total motion of the throttle tip is less than 0.004" and the motion of the reaction diaphragm is less than this, the diaphragm does not change in effective area, and the air pressure on the reaction diaphragm is, therefore, a straight line function of the variable force. Calibration results from establishing the ratios of lever lengths, the size of the reaction diaphragm, and the desirable range of transmitted pressure values. The pressure may be conducted to a remote location by means of copper tubing, and a pressure gage connected to the tubing may be graduated directly in terms of the measured variable. The pressure may also be used as the measuring impulse for automatic regulation.

FLEXIBILITY—Range is easily changed in the field by changing the position of the reaction diaphragm along the weighbeam. If this is not sufficient, the size of the reaction diaphragm may be readily changed. In the case of pressure and differential pressure transmitters, the size of the measuring element diaphragms may also be changed readily.

EASY TO SERVICE—The cover can be completely removed so that all parts are readily accessible. All parts are of standard machine size and do not require special or watchmaker's size tools.

EXPLOSION PROOF—An inherrent characteristic of pneumatic transmission. Where electric chart drives are required in recording receiver, they can be supplied in explosion-proof housings meeting underwriter's requirements.

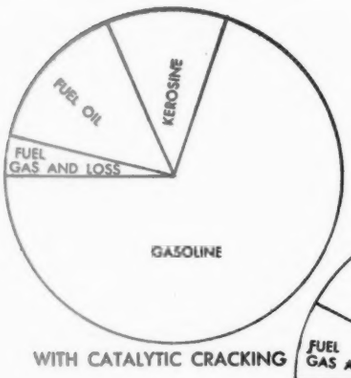
SMALL DISPLACEMENT—The small motion of diaphragms eliminates many troubles encountered with deflection type instruments. Most of the difficulties, encountered with liquid seals, condenser chambers and purging systems, result from the displacement of the measuring elements of deflection type instruments. The extremely small displacement of the measuring elements of Republic transmitters eliminates practically all of these troubles.

RANGE SUPPRESSION—The force balance principle permits much higher range suppression than can be done with ordinary deflection type instruments. Up to 80% of the maximum scale range of pressure and differential pressure instruments can be suppressed, while in density transmitters the amount of suppression is practically independent of the scale range.

COMPOUND RANGES—Compound ranges (plus and minus scales) can be furnished in practically any combination desired.

THE ABOVE WAS TAKEN FROM OUR DATA BOOK No. 1000 ON PNEUMATIC TRANSMISSION • WRITE FOR COPY

REPUBLIC FLOW METERS CO.
2240 Diversey Parkway, Chicago 47, Illinois



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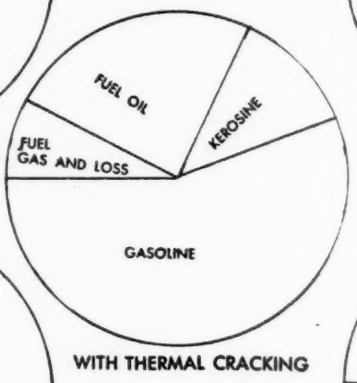

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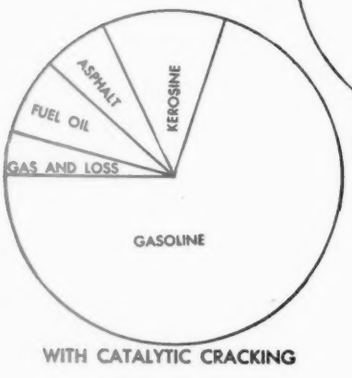
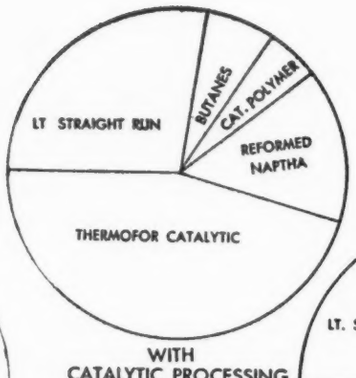


WITH CATALYTIC CRACKING

FIG. 10. DISTRIBUTION OF PRODUCTS



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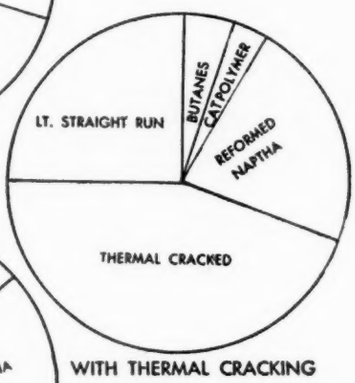

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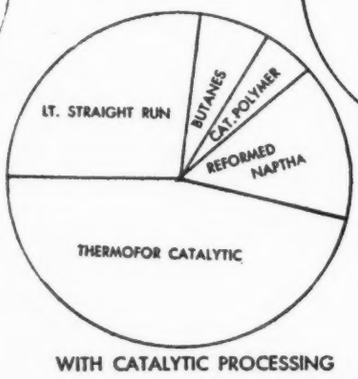

WITH CATALYTIC PROCESSING

FIG. 11. COMPOSITION OF GASOLINE

were burned by merely introducing the theoretical quantity of air at the bottom and blowing it through the catalyst bed in one pass, the heat liberated would cause a temperature rise of the order of 800 to 1200°F. in the catalyst. Consequently, the kiln is divided into zones from 5 to 12 in number depending upon the amount of carbon to be burned as determined for design purposes by pilot plant runs on the refiners charge stock. A kiln zone consists of a bed of catalyst having residence time of the order of 5 to 10 min. into which combustion air is introduced at the middle, the air flowing both upward and downward to outlet flue gas collectors above and below the inlet distributors. The quantity of air supplied and the temperature of the air are controlled for each zone so that the temperature of the catalyst in the zone rises about 150°F. to a maximum of 1100°F. When the catalyst has reached 1100°F., which is well below the safe operating temperature, it continues in its descent over a bank of cooling coils where the temperature is reduced to about 950°F. at which temperature the catalyst enters the next zone below, where the same procedure is repeated. In the upper zones of the kiln the amount of carbon burned off in each zone is of the same magnitude, but as the carbon burnoff progresses a longer time is required to burn off the remaining carbon. Consequently, the residence time in the lower zones increases and the residual carbon is burned off more slowly until at the bottom or clean-up zone the residence time is of the order of 20 min. In the upper zones the outlet flue gas is high in CO_2 and H_2O, most of the oxygen having been consumed. The flue gas from the bottom zone is high in oxygen, for at this stage carbon concentration has been reduced so that a high oxygen concentration is necessary to achieve the very low final residual carbon on catalyst obtained in the TCC kiln. The lowest bank of cooling coils is used for a final adjustment of kiln outlet temperature; i.e., reactor inlet temperature.

Kiln variables that are subject to control are the inlet air rate, the inlet air temperature, and the number of cooling coils in service. Any one of these three variables can be changed to maintain close control of the kiln. Best operation to date has been accomplished by leaving all cooling coils in service, and by merely manipulating air temperatures and air rates to the various zones stable kiln conditions with excellent carbon burnoff are accomplished. Fig. 6 shows a typical vertical cross-section and temperature pattern through a kiln. The pattern of temperature rise in a kiln and the effect on temperature as a catalyst is passed over the cooling coils may be observed. Attention is directed to the low maximum temperatures in the initial zones where hydrogen and sulphur oxide concentrations are at a maximum.

The inlet air temperature to the kiln is controlled by the addition of heat in an air line burner. Line burners may be fired with gas or oil and operate at the pressure of the air inlet duct system, which is in the range of 1 to 2 lb. per sq. in.

The blower supplying combustion air operates at a discharge pressure of 1½ to 2 lb. per sq. in. and handles cold air

TABLE A
TCC unit yields

Feed, bbl. per calendar day	Case A	Case B
Virgin gas oil	2000	2000
Vacuum gas oil		450
Visbreaker gas oil	315	..
Visbreaker gasoline	97	..
Total fresh feed	2412	2450
Recycle gas oil	2315	2450
Total reactor throughput	4727	4900
Yields on fresh		
Butane-free gasoline, vol. per cent	65.0	64.8
Butenes, vol. per cent	5.6	5.8
Butanes, vol. per cent	9.4	9.5
Cycle gas oil, vol. per cent	16.3	15.1
Dry gas (F.O.E.), vol. per cent	10.2	10.4
Propylene, vol. per cent	5.2	5.5

TABLE B
Thermal 2-coil cracking yields

Reduced crude charge, bbl. per calendar day	2750
Butane-free gasoline, vol. per cent	44.7
Butenes, vol. per cent	2.2
Butanes, vol. per cent	3.0
Tar (8 deg. API), vol. per cent	42.5
Dry gas (F.O.E.), vol. per cent	12.4
Propylene, vol. per cent	3.0

TABLE C. Thermal reformer yields.

Feed	Base Case	Case A	Case B
Virgin heavy naphtha, bbl. per calendar day	900	640	640
Octane No. CFR-M	37.0	34.5	34.5
Yields			
Butane-free gasoline, vol. per cent	71.0	84.0	84.0
Butenes, vol. per cent	4.5	3.3	3.3
Butanes, vol. per cent	4.5	3.2	3.2
Tar, vol. per cent	4.5	2.5	2.5
Dry gas, (F.O.E.), vol per cent	15.7	7.9	7.9
Propylene, vol. per cent	4.0	3.0	3.0
Gasoline octane No. CFR-M (C_4 free)	67.5	57.0	57.0

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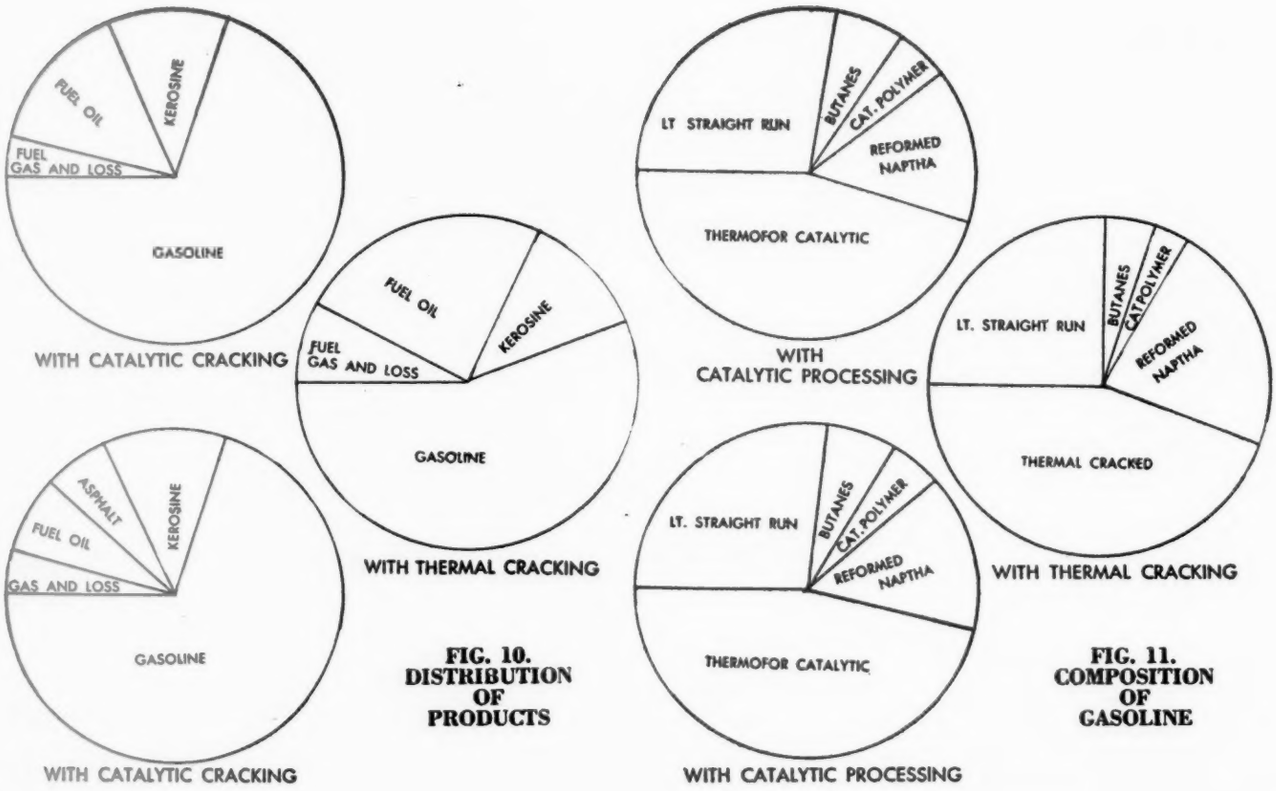

FIG. 10. DISTRIBUTION OF PRODUCTS

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Virgin heavy naphtha, bbl. per calendar day	900	640	640
Octane No. CFR-M	37.0	34.5	34.5
Yields			
Butane-free gasoline, vol. per cent	71.0	84.0	84.0
Butenes, vol. per cent	4.5	3.3	3.3
Butanes, vol. per cent	4.5	3.2	3.2
Tar, vol. per cent	4.5	2.5	2.5
Dry gas, (F.O.E.), vol per cent	15.7	7.9	7.9
Propylene, vol. per cent	4.0	3.0	3.0
Gasoline octane No. CFR-M (C_5 free)	67.5	57.0	57.0

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only. At this low discharge pressure and with air quantities in the range of 10,000 to 25,000 cu. ft. per min. the horsepower requirement for this blower is in the range of 100 to 300 hp. The combined horsepower required for supplying regenerating air and circulating catalyst consequently is a relatively low figure.

Materials of kiln construction are selected for the conditions existing or anticipated in the kiln. Low chrome alloy construction is used for the air distributors and collectors. The kiln walls are internally insulated and refractory lined. Cooling tubes are 1¼ chrome alloy. The rest of material in a TCC unit is carbon steel except as altered by specific corrosive conditions. The reactor-kiln section of the TCC unit may be modified to permit handling of corrosive stocks for a minor increase in installation cost. It may be noted that equipment in a TCC unit is generally of standard type readibly obtainable, and maintenance work can be easily handled by labor normally used in any refinery.

The steam generating system in the TCC unit operates on the principle of forced circulation of feed water to the kiln cooling coils. The circulating pump has a capacity of 300 to 500 gal. per min., which is many times the feed water rate actually required for the steam generated. Consequently, the mixture of steam and water from the kiln is returned to the drum from which the pump takes suction, where the steam is flashed, passes through a demistifier and thence to the plant steam system. The steam drum is situated near ground level where all controls are readily accessible. Scale deposit in the kiln tubes has been negligible due to the fact that the tubes operate flooded with water. Although it would be possible to use all welded coil construction, it is considered desirable to use a removable plug type header on one end of the tube coils so that they can be inspected or cleaned if necessary.

The designing of a TCC unit for capacities in the range of 1000 to 5000 bbl. per day posed the problem of retaining all the inherent simplicity and safety features of the larger TCC units and at the same time provide a low cost unit. Actually it has developed that the features of simplicity and low cost are closely related so that in the small TCC units now available, simplicity and safety have been retained and the cost reduced well below that of the scaled-down versions of the conventional early designs. These results were obtained by condensing the size of the equipment, combining equipment where possible, and omitting features and equipment proved unnecessary by experience. For example, in the early design a separate hot catalyst storage drum is installed to contain the catalyst when the unit is shut down and the reactor and kiln are to be inspected. In the low cost TCC unit this storage space has been placed above the reactor and surrounding the seal leg, which necessarily must be about 50 ft. high. The reactor, hot catalyst storage drum, and reactor feed hopper are thus built and erected as one vessel at a marked saving in cost.

In small TCC units the regenerated catalyst circulating rate can be reduced to 50 to 75 tons per hr. This permits the use of a single elevator instead of two elevators, the single elevator being of the same standard design as on the large units with the exception of the elevator bucket arrangement. The spent catalyst and the regenerated catalyst are handled in the same bucket by the device of providing separate compartments in the bucket for each. In this arrangement the colder spent catalyst is placed in compartments on each end of the buckets next to the chain and the hotter regenerated catalyst in the middle compartment. As elevator chain has been

TABLE D
Total motor gasoline octane numbers

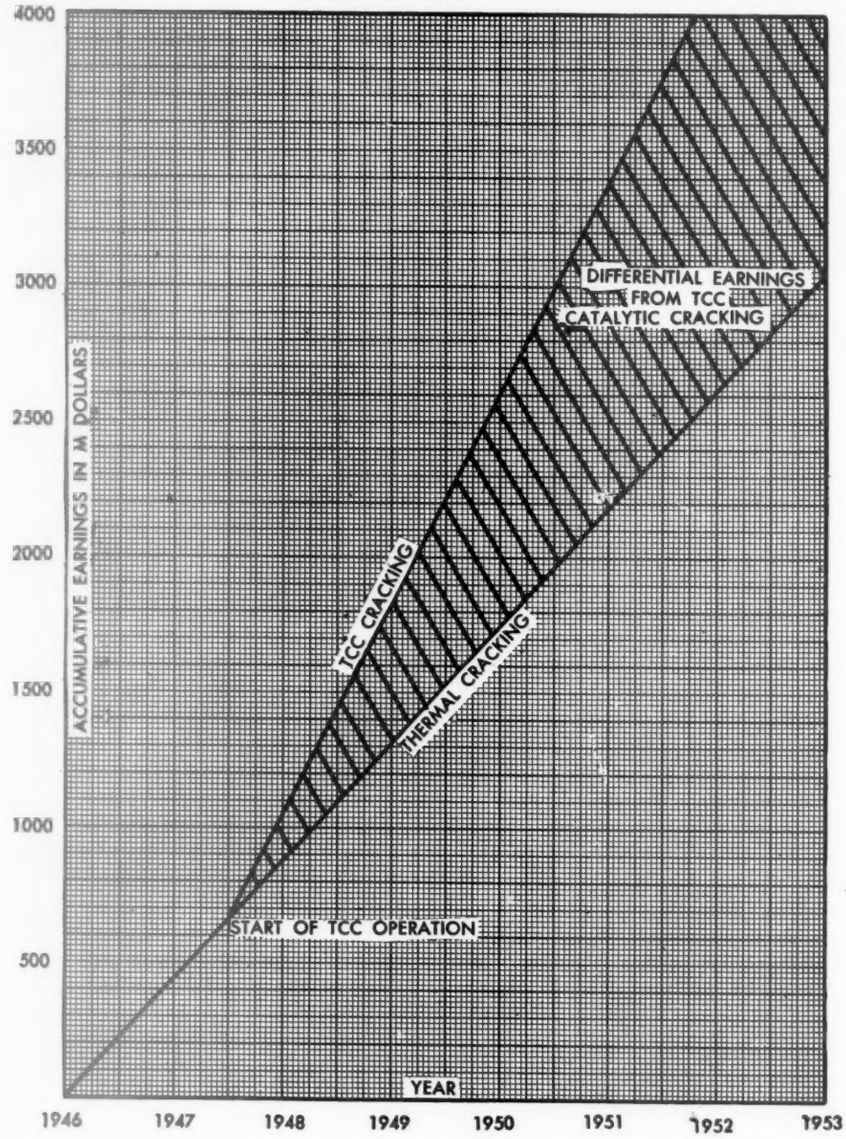
Total gasoline (10-lb. R.v.p.)	Base Case	Case A	Case B
CFR-M (clear)	66.7	69.9	70.3
+1 cc. TEL per gal.	74.5	76.8	77.1
+2 cc. TEL per gal.	77.0	80.0	80.3
+3 cc. TEL per gal.	79.0	82.0	82.2
cc. TEL to 79.0 CFR-M	3.00	1.60	1.50

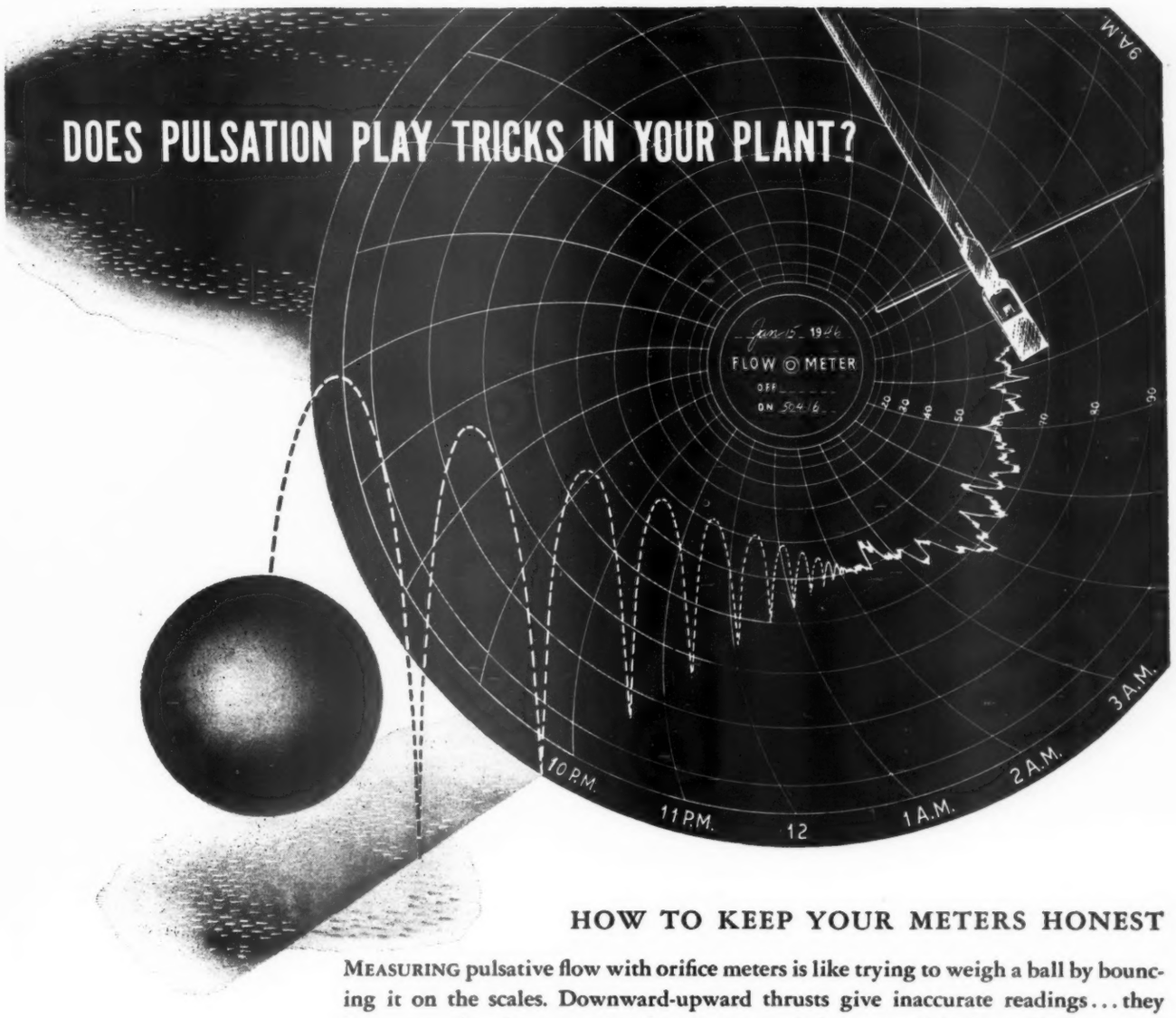
TABLE E. Direct operating costs
TCC feed preparation and cracking

	Case A	Case B
Fresh feed, bbl. per calendar day	2412	2450
Total feed, bbl. per calendar day	4727	4900
Item	Dollars per day	Dollars per day
Operating labor (4 men per shift at $1.30)	125	125
Supervision and payroll burden	31	31
Works expense	70	70
Maintenance (labor and material)	123	110
Catalyst	120	120
Utilities:		
H.P. steam at $0.24 per M lb.	18	—6*
Power at 0.7 cents per kw-hr.	7	6
Cooling water at 0.5 cent per M. gal.	17	15
B.f.w. feedwater at $0.15 per M. gal.	6	6
Fuel at $0.15 per MM. B.t.u.	153	135
Total direct operating cost	$ 670†	$ 612‡
Cents per bbl. fresh feed	27.8	25.0
Cents per bbl. total feed	14.2	12.5

*Net production of high pressure steam.
†Includes operating expense of visbreaker circuit.
‡Does not include vacuum tower operating expense.

FIG. 12. TCC ECONOMICS OF PROCESSING VERSUS THERMAL CRACKING





HOW TO KEEP YOUR METERS HONEST

MEASURING pulsative flow with orifice meters is like trying to weigh a ball by bouncing it on the scales. Downward-upward thrusts give inaccurate readings... they happen so fast the measuring instrument can't keep up with them. To keep your orifice meters honest, pulsative flow must be converted into a steady stream. The FLUOR Pulsation Dampener is the practical answer to this problem.

For example—a large Eastern Gas Company pumps gas into underground storage during the summer and withdraws it during the winter when consumer load is heaviest. As storage reservoir pressure drops, it becomes necessary to compress the gas to maintain pressure in the mains. Pulsations set up in the gas stream by the compressors threw the meters off by such substantial amounts that the Company was unable to determine how much gas was being pulled out of the reservoir. FLUOR Pulsation Dampeners installed in the suction lines between the meters and compressors eliminated this condition and made accurate measurement possible.

The FLUOR Pulsation Dampener changes pulsative flow into smooth, steady flow... with beneficial effect on frictional losses, horsepower savings and rate of flow. If vibration plays *tricks* in *your* plant, it may be due to pulsations in air, gas or vapor lines. In that case, the FLUOR Pulsation Dampener is your answer.

fc
SINCE 1890

FLUOR PULSATION DAMPENER

THE FLUOR CORPORATION, LTD. 2500 South Atlantic Boulevard, Los Angeles 22
NEW YORK • PITTSBURGH • KANSAS CITY • HOUSTON • TULSA • BOSTON

ENGINEERS • MANUFACTURERS • CONSTRUCTORS

TABLE 3. Summary of economics.

Case No.	Base case			"A"		"B"	
	Cents per gal.	Bbl. per calendar day	Dollars per day	Bbl. per calendar day	Dollars per day	Bbl. per calendar day	Dollars per day
Revenue							
10 lb. R.v.p. motor gasoline	6.250	2814	7387	3467	9101	3499	9185
Kerosine	4.250	600	1071	600	1071	600	1071
Residual fuel	2.145	1210	1089	727	654	687	618
Dry gas (F.O.E.)	2.145	437	393	287	258	271	244
Excess butane	1.450	....	....	26	16	12	7
Total revenue			$9940		$11,100		$11,125
Operating costs							
Crude	3.33	5000	$7000	5000	$7000	5000	$7000
Crude distillation		5000	300	5000	300	5000	300
Vacuum reduction		..	..	..	..	750	89
TCC cracking		..	..	2412*	670	2450†	612
Thermal reforming		900	168	640	146	640	146
Thermal cracking		2750	400	..	..	..	..
Debutanization		..	18	..	20	..	20
Catalytic poly		92	115	166	153	170	157
Gasoline inhibitor		2814	3	3467	3	3499	3
Taxes, interest, insurance (incremental)		..	21	..	134	..	154
TCC royalty		..	..	2412	121	2450	123
Thermal royalty		2750	83	..	..	..	..
Catalytic poly. royalty		92	19	166	35	170	36
TEL to 79 CFR-M (M. cc's)		355	638	233	419	220	396
Total operating costs	..		$8765		$9601		$9036
Earnings per day			1175		2099		2089
Differential payout period (year)					2.45		2.92
Investments (process equipment only)							
Revamp thermal and install TCC catalytic section					$775,000		$800,000
Catalytic polymerization			$150,000		200,000		200,000
Vacuum distillation			..		..		125,000
Total			$150,000		$975,000		$1,125,000

*Visbreaking and 1:1 recycle cracking. †1:1 recycle cracking.

found to operate more than 100°F. below the adjacent catalyst, the chain temperature will be in the range of 750 to 800°F.

The only cyclone separator to be installed will be that provided at the discharge of the elutriator where on a 100 ton per hr. unit about 1500 lb. per day of fines and dust is removed during elutriation. Experience has shown that cyclone separators in the flue gas outlet ducts from the kiln are unnecessary as little or no dust carry-over has been encountered except in the few cases where leakage due to a mechanical detail existed. The elutriator used for the purpose of controlling catalyst size has been placed relatively close to ground level and arranged in combination with the fines bin and cyclone separator where all this equipment is more easily accessible.

A considerable saving in structural steel is accomplished on the new small TCC unit design by utilizing the inherent strength of the kiln and reactor as structure to support all platforms required and to provide top guides for the bucket elevator, which is situated between them. In addition to these major changes, which in no way effect the ruggedness, safety, and flexibility of the TCC unit, a great many improvements in mechanical details have been made as a result of experience with the units now operating. The new small units will operate on natural clay or synthetic catalyst interchangeably. It may be said that in all respects the small sized TCC unit is equal to the large units and in many respects it will be a more closely integrated unit.

● **Economics.** To illustrate the advantages to be gained by the installation of TCC equipment an economic study has been prepared for what is considered a typical refinery situation. It has been assumed that a refinery processes 5000 bbl. per calendar day of typical Mid-Continent type crude in topping, two-coil thermal cracking and naphtha reforming equipment. The two cases illustrating TCC processing are based on revamping of existing equipment and addition of a TCC reactor-kiln section for processing the material presently going to two-coil thermal cracking.

The cases considered are briefly outlined as follows:

BASE CASE

Present operation, crude topping, two-coil reduced crude cracking, deep naphtha reforming and catalytic polymerization of C_3 and C_4 unsaturates.

CASE "A"

Crude topping, moderate naphtha reforming, TCC 1/1 recycle cracking of overhead from flashing reduced crude with integral visbreaker circuit for flash tower bottoms; catalytic polymerization of C_3 and C_4 unsaturates.

CASE "B"

Crude topping, mild naphtha reforming, TCC 1/1 recycle cracking of overhead from reduced crude flash and vacuum flash towers; catalytic polymerization of C_3 and C_4 unsaturates.

The cases presented are based on the assumption that 600 bbl. per calendar day (12 per cent) of kerosine would be marketed. The price structure and utility values used are listed below:

Feed and products	
Mid-Continent crude, per bbl.	$1.40
Housebrand gasoline (78 CFR-M), cents per gal.	6.00
Premium gasoline (83 CFR-M), cents per gal.	7.00
Kerosine, cents per gal.	4.25
Fuel oil (No. 6), per bbl.	$0.90
Excess butanes (above 10-lb. R.V.P. gasoline), cents per gal.	1.45
Fuel gas, cents per MM B.t.u.	15.00
Utilities	
Steam (H.P.), per M. lb.	$0.24
Power, cents per kw.-hr.	0.70
Cooling water, cents per M. gal.	0.50
Treated water, per M. gal.	$0.15
Clay catalyst, cents per lb.	4.00
Labor (avg. rate) per man-hour	$1.30

The gasoline price of 6.25 cents per gal. is based on 75 per cent Housebrand (77.5 CFR-M) at 6.00 cents per gal. and 25 per cent premium (83 CFR-M) at 7.00 cents per gal.

The above prices are, of necessity, arbitrarily chosen. For an individual refiner to obtain a true picture, his actual price structure should be substituted. The direct operating costs for the TCC feed preparation and cracking section are appended in Table E.

Table 3 gives a complete summary of 7, 8, and 9 show the process schemes outlined above. Basic yields, capacities of the various refining units, and clear and leaded octane numbers of blended gasolines are shown in Tables A, B, C, and D.

Table 3 gives a complete summary of overall refinery economics for the 3 cases considered. Case A shows a payout period of 2.5 years based on the new investment required. Earnings for this case over and above the base case are shown graphically in Fig. 12. Case B, on the basis of cutting back asphalt for fuel oil production, shows a slightly lower return on a large investment. This case, however, gives greater flexibility in that fuel oil, or asphalt, or both may be produced as market requirements dictate. For those refiners who produce asphalt or lube oil this plan might be of considerable interest. Evaluation of asphalt product at any price higher than fuel oil value will, of course, increase the earnings of this case.

A chart has been prepared (Fig. 10) based on the 3 cases presented, which shows the distribution of refinery products with and without the TCC unit. It is immediately apparent that a considerable increase in gasoline yield is obtained by the installation of TCC equipment. This increase is obtained from a decrease in fuel oil and fuel gas.

Fig. 11 shows the composition of over-refinery gasoline for the 3 cases. The major effects of the catalytic installation shown are a slight increase in catalytic polymer, butanes and light straight run and a decrease in reformed naphtha. Cracked gasoline, thermal or catalytic, remains nearly constant, being slightly higher in Cases A and B than the base case. The lower reformed naphtha and the higher butanes in the gasoline are explained by the fact that with the installation of the TCC equipment, it is not necessary to reform as severely as in the thermal case to reach the same octane level and lead requirement for the motor fuel. The reforming operation therefore has been reduced both in charge rate and severity. This results in a smaller quantity of lower octane number reformed naphtha and a greater requirement of butanes to make constant vapor pressure total gasoline.

The small TCC unit will answer the postwar quality problem for operators of small refineries by producing higher yields of excellent quality gasoline at a reasonable manufacturing cost, and by providing ample allowance for further increases in quality should the competitive situation so demand. ★ ★ ★

High Pressure Absorption*

By HENRY N. WADE,

Stearns-Roger Manufacturing Company

Along with the development of the Natural Gasoline Association, the science of absorption of gasoline from natural gas has come a long way during the past 25 years. At the time of the formation of the Association, absorption plants were almost entirely low pressure affairs, treating gas at pressures around 30 to 45 lb. gauge. A very few plants operated on gas entering some of the very earliest transmission lines, at pressures around 300 lb., ranging up to as much as 500 lb. in one or two instances. Large, long distance transmission projects were still far in the future, so that there was no reason for treating gas at the high pipe line pressures that have now become conventional. Further than this, none of the deep, condensate type producing formations had been discovered, and if they had been it is doubtful whether anyone would have thought of processing the gas at really high pressures, since the idea of pressure maintenance or cycling was not to develop on any commercial scale for another 10 to 15 years.

As time went on, the development of high pressure natural gas sources, combined with high pressure transmission lines, led necessarily to the development of plants to process the gas at line pressure. This type of development culminated, as far as I know, in the design and construction of the Fritch, Texas, natural gasoline plant of the Texoma Natural Gas Company. This plant was designed for an operating pressure of 800 lb. per sq. in., at least 30 per cent higher than any used up to that time. It was also designed for what was then an extraordinarily large volume of gas in one plant: 200,000,000 std. cu. ft. a day.

The Fritch plant held its place as the highest pressure absorption plant until about 1937, which marks the beginning of the development of Gulf Coast condensate production combined with reinjection of the stripped gas. From this time on, the absorption pressure in such plants has rapidly risen, to such an extent that now absorber operating pressures of 1500 to 2000 lb. gauge are more or less an everyday matter.

● **General factors affecting absorber pressure.** The ceiling of approximately 800 lb. absorption pressure for pipe line plants was set by the limitations in the design of the pipe lines themselves. Taking into account all the factors affecting the manufacture of the pipe itself and its handling and field fabrication into a pipe line, the most economical answer for long lines and large quantities of gas dictates maximum operating pressures in the neighborhood of 800 lb. gauge. The comparatively recent development of absorption plants operating at pressures up around 2000 lb. gauge has developed from the necessities of recycling or pressure maintenance operations.

Obviously, it is necessary to allow some margin between initial producing wellhead pressure and the absorber pressure in order to provide for pressure drop in the extensive gas-gathering pipe system, and for cooling and controlling the flow of gas before its entrance into the absorption system. The spread in pressure between the maximum producing wellhead pressure and the absorber pressure must also be large enough to enable the weakest producing well to deliver its quota of gas into the gathering system. This requires that there must be some throttling of pressure at the wellhead on those producing wells which have the highest producing pressures. Finally, some allowance must be made for the eventual decline of producing well pressure that will result in time from the withdrawal from the formation of the gas volume equivalent of the liquid hydrocarbons produced by the extraction plant, plus whatever net dry gas volume is permanently removed from the structure for use as fuel at the plant and in the field operation, or for delivery to pipe lines.

How much of an allowance should be made for this unavoidable decline in pressure obviously can be determined only through a study of all of the factors surrounding the operation of the property. If a relatively short life is expected, the spread between initial producing wellhead pressure and absorber pressure should be made great enough to permit operation of the plant for perhaps half the life of the field before extensive changes will be required to allow operation at the depleted pressures that will exist toward the end of the life of the field. On the other hand, if the gas reserves are large enough to show an expected life of say 20 years or more, the absorber pressure should be just as close to the producing pressure as satisfactory load division between the producing wells will permit. In a long-lived property the rate of pressure decline will be slow and there will be ample time to pay out the initial investment and to plan suitable plant modifications or additions when the necessity for them arises through pressure decline.

In a typical large system of this kind the produced gas arrives at the wellheads at a pressure around 2400 lb. per sq. in. Experience in this field has shown that the injection pressure must be about 3500 lb. per sq. in. in order to deliver a satisfactory volume back into the formation. The field piping system was designed so that the overall pressure drop from the most remote producing well into the plant is about 100 lb. An additional allowance of about 100 lb. was made for control of the individual well deliveries into the gathering system, so that the gas arrives at the plant at a pressure of about 2200 lb., or 200 lb. below the average producing wellhead pressure.

In order to make a reasonable allowance for the eventual decline of the producing pressure, the absorption system was designed for an absorber operating pressure of 1800 lb. per sq. in. gauge. Thus the producing pressure can decline 400 lb. before it will be necessary to even consider any change or additions to the plant as originally constructed.

● **Effect of absorber pressure on compressor horsepower.** It is obvious that on a cycling system it is desirable to set the absorber pressure as high as the producing conditions will permit, in order to keep the compression ratio required for injection of the residue gas as low as possible. In the case of the cycling system just referred to, the pressure required on the injection gas at the plant headers is 3500 lb. With the absorber operating at 1800 lb., this corresponds to a compressor ratio of 1.94, requiring compressor horsepower of about 42 per million standard cubic feet of gas injected per 24 hours. Since the full-load capacity of the plant is 210 million standard cubic feet per 24 hours, this calls for a total compressor horsepower of 8820, neglecting the effect of deviation on the actual horsepower requirements.

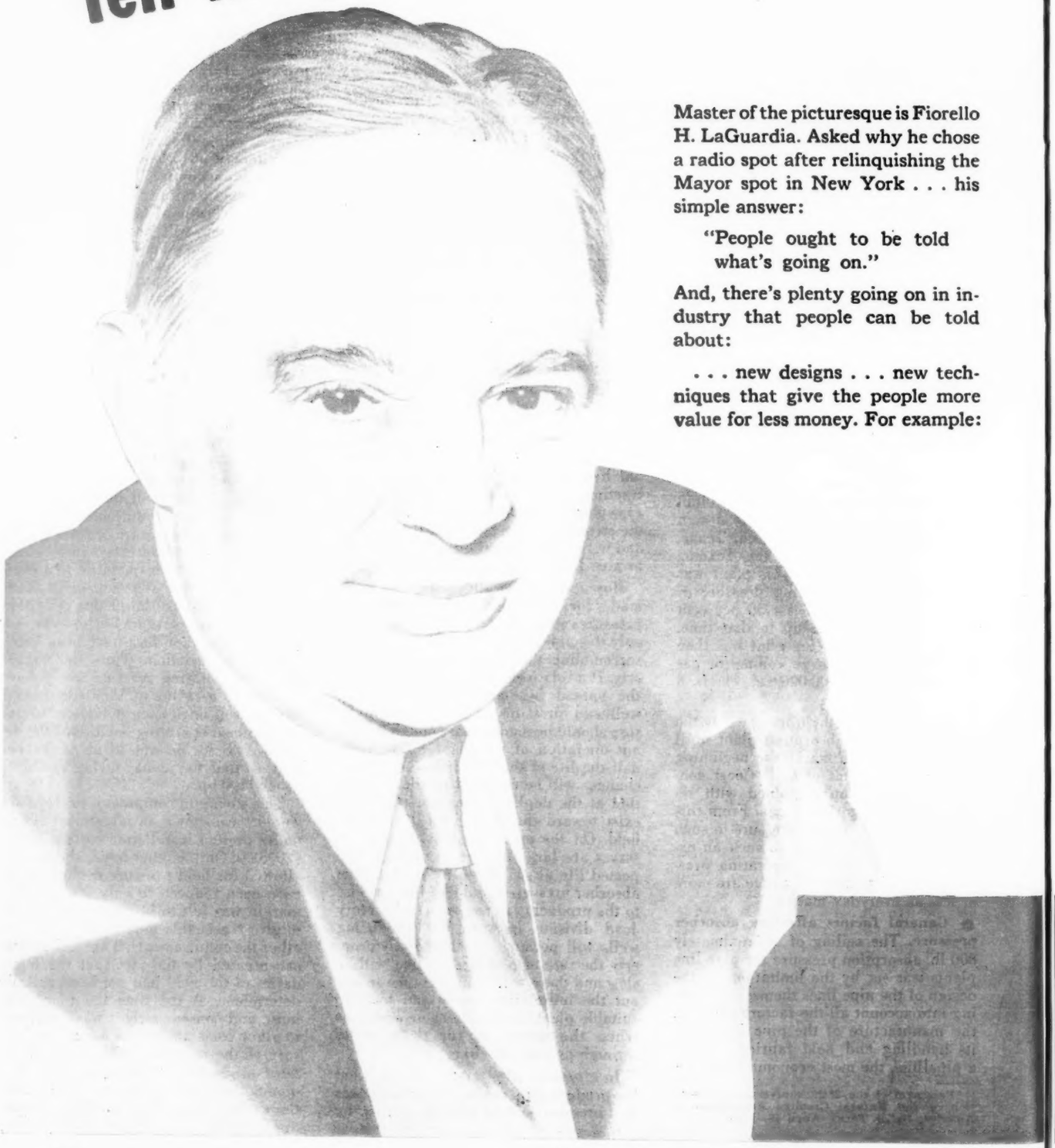
If an absorber pressure of 2000 lb. had been chosen, the compression ratio would have been 1.74, corresponding to a compressor horsepower requiremeut of about 36 hp. per million. Under this condition the total compressor horsepower required would therefore have been 7560, neglecting deviation. Thus the higher absorber operating perssure would have resulted in a saving of 1260 compressor horsepower, neglecting deviation. Under the assumed operating conditions the deviation would amount to about 15 per cent, so that the actual saving would be about 1100 hp.

This saving in compressor horsepower would have shown an investment saving under present installation costs of about $200,000. On the other hand, the margin allowed for field pressure decline would have been reduced to only 200 lb. This margin was felt to be entirely too small to give reasonable assurance of meeting all of the requirements. This feeling was accentuated by the fact that the boundaries of the field had not been entirely determined at the time the plant was built. and consequently it was necessary to allow some additional margin to take care of the possibility that some of the later producing wells might show producing wellhead pressures lower than the earlier wells. This condition would.

*Presented at the 25th Anniversary Convention of the Natural Gasoline Association of America, Dallas Texas, April 18, 1946.

then he said to himself:

Tell the people what's cookin'



Master of the picturesque is Fiorello H. LaGuardia. Asked why he chose a radio spot after relinquishing the Mayor spot in New York . . . his simple answer:

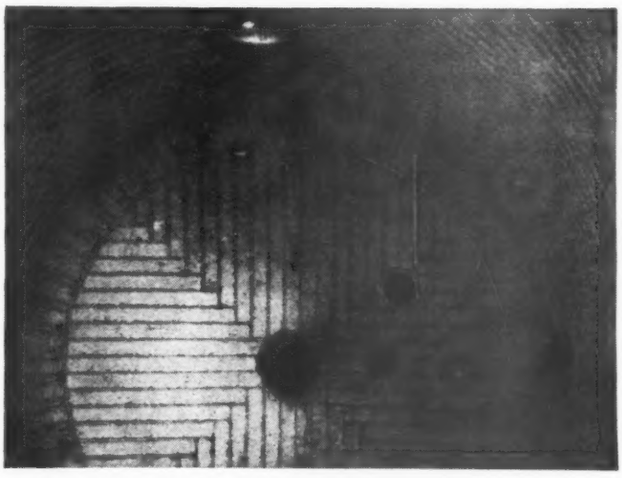
"People ought to be told what's going on."

And, there's plenty going on in industry that people can be told about:

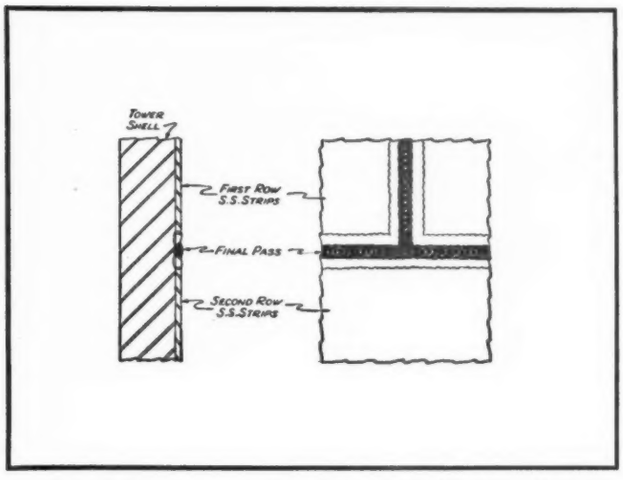
. . . new designs . . . new techniques that give the people more value for less money. For example:

***LOOK, MR. LA GUARDIA,* at this good word from the oil refining industry:**

Here's new life for that old vessel at low cost



Interior of refinery vessel after completion of stainless steel lining.



How strips are spaced and final weld bead applied.

Old refinery vessels are being converted to modern high temperature service by lining them in the field with stainless steel. This saves the expensive shell and fortifies it for the severe corrosive conditions of modern fractionating. Here's how the K. E. Luger Company does it:

Stainless Steel Strips. Use type 410 stainless steel, .078" thick. Cut strips 3" to 4½" wide (the higher the operating temperature of vessel, the narrower the strip). Maximum length of strips 30".

"Stainweld D" Electrode. This Lincoln shielded arc electrode, for all positions, is of 25% chrome, 20% nickel. Use ⅛" size with welding current of 75 to 90 amps., D.C. Hold short arc to minimize effect of heat on stainless steel.

Lining Procedure. Tack weld each strip tightly in place, then completely weld with stringer bead around edge, making sure that each bead is perfect—no pin holes. When starting new electrode, back-step about ½" from where arc was broken. Welder should clean slag from bead thoroughly and inspect each strip as completed. Apply adjacent strip so that a small gap (about ⅛") is left between its weld and that of the previous strip. In lining side wall, apply strips horizontally so that maximum amount of welding is in horizontal position rather than vertical.

Final Steps. After interior surface of vessel is completely lined with the stainless steel strip, sand blast thoroughly and have thorough inspection made by authorized inspector. Patch any flaws or pin holes by welding. Then make filler bead between welds of adjacent strips. This final step—a stringer bead of stainless steel electrode—completes the lining of the tower and leaves no point uncovered. Clean the final beads thoroughly and inspect.

Link-up with Lincolneering to help solve *your* maintenance and construction problems with arc welding.

THE LINCOLN ELECTRIC COMPANY • DEPT. 382 • CLEVELAND 1, OHIO

America's greatest natural **recourse**

ARC WELDING

of course, require a general reduction in the operating pressures in the field gathering piping in order to permit such wells to deliver their allotment of gas.

● **Effect of absorber pressure on plant cost.** During the preliminary figuring in connection with the cycling system discussed, a set of calculations was made to determine the effect on the cost of the gasoline plant itself of various absorber pressures. These figures covered the range of absorber pressure from 1100 lb. to 2000 lb. Since the plant was required to give a combined butane production efficiency of 80 per cent, the calculations were carried through using this butane efficiency as the criterion for determining the required rate of oil circulation in the plant. Somewhat to the surprise of the engineers making these calculations it was found that the total plant lean oil circulation was almost constant over this entire range of pressure.

The explanation for this apparent paradox lies in the fact that, upon entering the top plate of the absorber, the lean oil almost instantaneously absorbs a very large amount of the residual light components remaining in the gas at that point. The actual figures showing the magnitude of this absorption are given later in a discussion of the absorption system in this plant.

For each mol of absorber oil entering the top of the 1800-lb. absorbers in the plant there is absorbed practically instantaneously 0.91 mol of methane, ethane, and propane. The combination of absorber oil and components dissolved out of the gas then leaves the upper plate or two as a liquid with a molal quantity of about 191 per cent of the molal quantity of lean oil entering the absorber. The fact that the gain in mols of the absorbent is derived principally from the dry gas itself does not in any way affect its efficacy in absorbing heavier components from the gas in the lower plates of the absorber.

Since the extent of this inflation of the absorber oil volume is almost directly proportional to the absolute pressure in the absorber, it follows that, with a given external lean-oil-to-gas ratio, the actual internal oil-gas ratio increases with the pressure enough to approximately compensate for the increase with pressure in the K factors of the heavier components which it is desired to extract, at least over this range of pressure.

Taking normal butane as an example, and assuming an effective absorber temperature of 110° F., the K chart values for methane and butane at 1000 lb. and 2000 lb. are as follows:

K FACTORS AT 110° F. EFFECTIVE TEMPERATURE

Component	at 1000 lb.	at 2000 lb.	Per-cent Change
Methane	4.4	2.7	63% decrease
Butanes	0.192	0.240	25% increase

The K value of methane at 1000 lb. is 4.4, whereas it is 2.7 at 2000 lb. Since the amount of methane absorbed in a given amount of absorber oil is, on the first approximation, inversely proportional to those K values, the top-plate absorption of methane at 2000 lb. would be 1.63 times its absorption at 1000 lb.

Referring now to the K values for an average mixture of butanes, the K at 1000 lb. is 0.192 and at 2000 lb. 0.240. In other words, in this range of pressure the butane is behaving in the so-called "retrograde" manner. Putting this another way, the increase in pressure reduces the relative absorbability of the butane in the inverse ratio of the K values. In the case of the butane K's this change amounts to 25 per cent.

Putting these factors together, if the effective internal absorber oil stream at 1000 lb. is taken as 100 per cent, the increase in the stream due to increase in pressure will make the effective internal stream 163 per cent at 2000 lb. However, in order to balance the decrease in absorbability of the butanes over this same pressure range an increase in internal oil rate of only 25 per cent would be necessary. Thus, as far as the absorption of butanes only is concerned the increase in pressure increases the internal oil rate faster than is really necessary. The proportionate increase in K factors is greater for the heavier components, and consequently the net effect of combining all of the factors proves to require a slightly higher external circulation of oil at 1000 lb. with a minimum at about 1400 lb., followed by a gradual increase up to 2000 lb. The difference between the maximum and minimum oil circulations required for equal butane extraction was less than 10 per cent over the entire range between 1000 lb. and 2000 lb. absorber pressure.

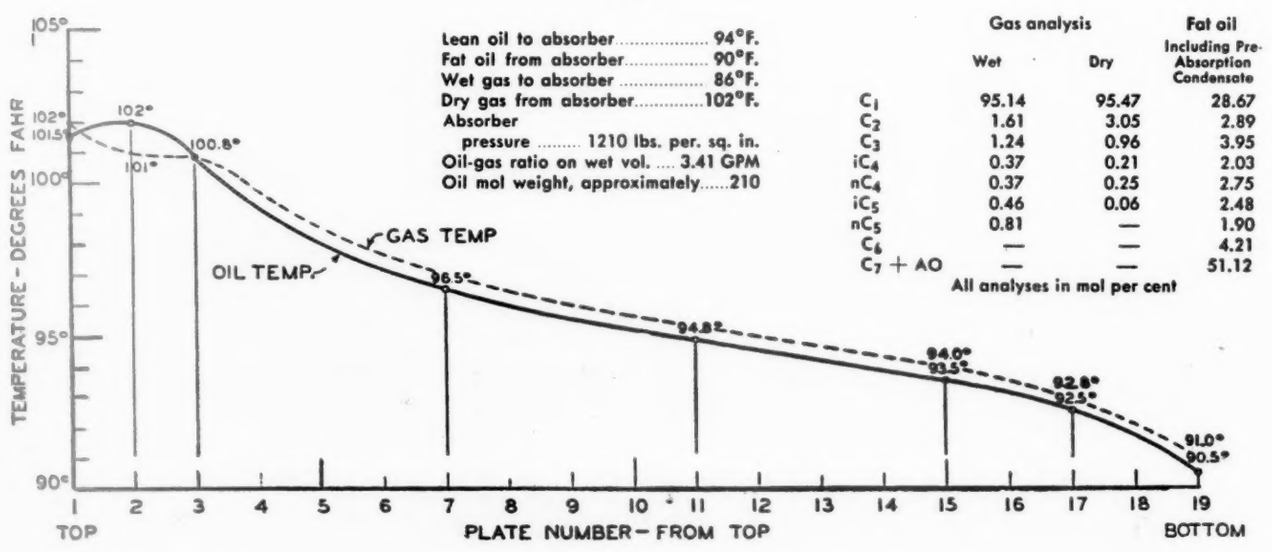
The inflation of the lean oil entering the absorber through absorption of methane and ethane near the top plate is illustrated directly by the absorber temperature curve shown in Fig. 1. This curve and the data accompanying it show the performance of an absorber in a South Texas field operating at a pressure of 1210 lb. gauge.

Inspection of this curve shows that although the absorber oil enters the top of the absorber at 94° F., and the gas enters the bottom of the absorber at 86° F., the temperature of the oil and gas on and between the upper plates rises to a maximum of 102° F. on plate No. 2, numbering from the top. The temperature then declines more or less regularly to the bottom of the absorber, where the oil and gas on the last plate both have a temperature of about 5° F. above the temperature of the incoming gas.

The abrupt rise in temperature at the top of the absorber reflects the effect of the heat absorption of the dry gas as it is dissolved in the lean oil. The amount of this absorption at this point is much greater than the absorption going on in any other part of the column and consequently the temperature produced is a maximum here. As the oil proceeds down through the absorber it is gradually cooled off by heat exchange against the relatively cool incoming gas.

The difference in temperature between

FIG. 1.



TUBE-TURN

TRADE MARK

WELDING FITTINGS AND FLANGES

TUBE-TURN WELDING FITTINGS—RANGE OF SIZES

Type of Fitting	Description	Standard Weight	Extra Strong	Schedule 160	Double Extra Strong	Light Gauge	
						Nominal Pipe Size	Iron Pipe Size
Elbows	90° Long Radius	½"-24"	½"-24"	1"-12"	½"-8"	4"-24"	3"-12"
Elbows	90° Short Radius	1"-30"	1½"-30"				
Elbows	45° Long Radius	½"-30"*	½"-30"*	1"-12"	½"-8"	4"-24"	3"-12"
Returns	180° Long Radius	½"-24"	½"-24"	1"-12"	3"-8"	4"-24"	3"-12"
Returns	180° Short Radius	1"-30"	1½"-30"				
Returns	180° Extra Long Radius	1"-2½"	1"-2½"				
Tees	Straight	½"-24"	½"-24"	½"-12"	½"-8"		
Tees	Reducing Outlet	½"-24"	½"-24"	½"-12"	½"-8"		
Reducers	Concentric & Eccentric	1x¾-24x20	1x¾-24x20		1x¾-8"x6"		
Caps		1"-24"	1"-24"		1"-8"		
Stub Ends	Lap Joint	1"-24"	1"-24"				
Nipples	Shaped. 90° to Header	1¼"-12"	1¼"-12"				
Nipples	Shaped. 45° to Header	1¼"-12"	1¼"-12"				
Saddles		2"-24"**					
Laterals	Straight	1¼"-24"	1¼"-24"				
Laterals	Reducing-on-Run	1¼"-24"	1¼"-24"				
Crosses	Straight	¾"-24"	¾"-24"				
Rings	Welding	¾"-12"	¾"-12"				
Sleeves	Welding	2"-24"**					

SUPER Tube-Turn 45° long radius elbows, 90° long radius elbows, and 180° long radius returns available in both Standard weight and Extra Strong in sizes from 3" to 12".

Tube-Turn welding fittings and flanges conform to applicable ASA and ASTM Standards. For further details please refer to Tube Turns catalog and data book No. 111.

*30" size short radius

**Since saddles and sleeves are used for external reinforcement only, they do not conform to iron pipe size thicknesses.

TUBE-TURN FORGED STEEL FLANGES—RANGE OF SIZES

	150 Lb.	300 Lb.	400 Lb.	600 Lb.	900 Lb.	1500 Lb.	2500 Lb.
Welding Neck	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Slip-on	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Lap Joint	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Threaded	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Blind	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Socket Type	¼"-24"	¼"- 4"		¼"-3½"			
Reducing-threaded or slip-on	¾"-24"	¾"-24"	¾"-24"†	¾"-24"	¾"-24"*	¾"-24"	¾"-12"
Orifice—threaded		1"-24"	4"-12"	4"-12"	3"-12"	1"-12"	
Orifice—slip-on		1"-24"					
Orifice—welding neck		1"-24"	4"-12"	1"-12"	3"-12"	1"-12"	
Long Welding Neck	1"-24"	1"-24"	1"-24"	1"-24"	1"-24"	1"-24"	1"-12"

†Dimensions on sizes thru 3½" same as for 600 lb. flanges.
*Dimensions on sizes thru 2½" same as for 1500 lb. flanges.

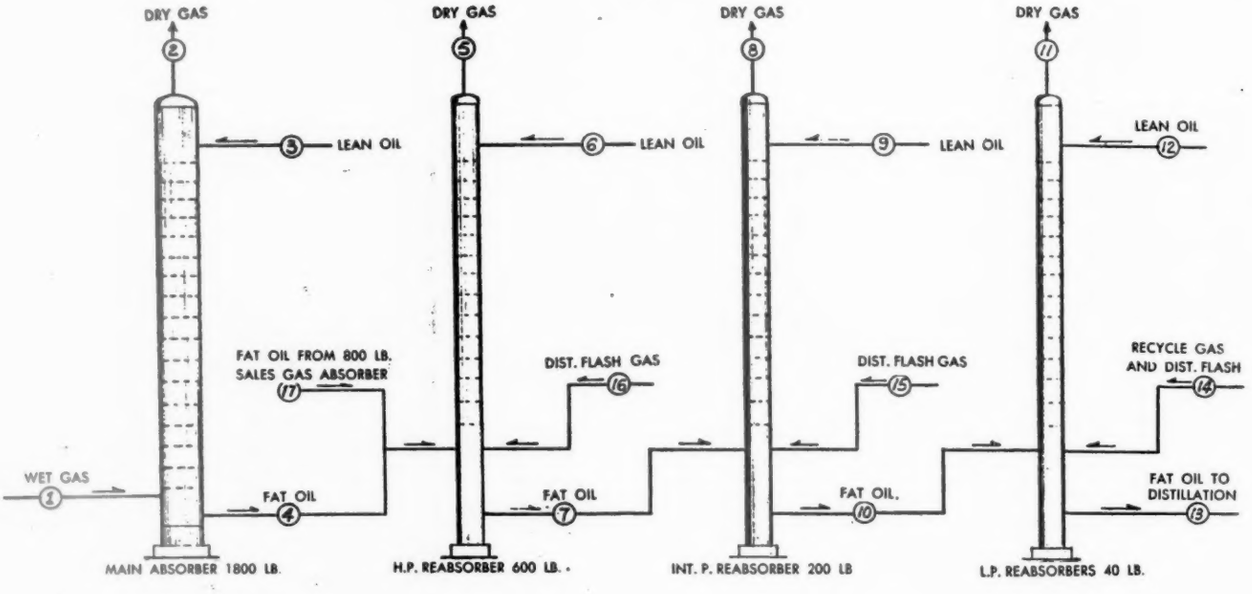
the incoming wet gas and the bottom plates reflects the absorption by the oil of the heavier components from the wet gas. However, the temperature rise produced by this absorption is almost completely masked by the effect of the large absorption of methane near the top of the absorber.

It is interesting to note that the general shape of this temperature curve is the opposite of that usually encountered in low pressure absorption. At pressures of 300 lb. or below the methane absorption, although appreciable, is not enough to produce any sharp rise in temperature near the top of the column. In low and moderate pressure absorbers most of the heat of absorption is derived from the heavier or "gasoline" components of the wet gas. Since this absorption occurs largely on the first few plates above the bottom of the absorber, the sharp temperature rise takes place near the bottom and the temperature then gradually declines as the gas passes upward through the plates to the top.

The actual figures showing the relationship between lean oil, dry gas, wet gas and fat oil quantities and compositions are shown on the accompanying diagram, Fig. 2, of the fat oil absorption and venting system in the plant under discussion.

The wet gas (1) enters the main absorbers at a pressure of 1800 lb. gauge, in the total quantity of about 610,000 mols per 24 hr. The dry gas (2) amounts to 550,000 mols. The difference of 60,000 mols is made up of about 43,000 mols of methane and ethane dissolved in the fat oil which must be eventually removed in the venting and fractionating system, and 17,000 mols of propane and heavier components out of which the production of the plant is derived. The absorber oil stream amounts to 53,200 mols per day, and is inflated almost immediately upon its entrance to the absorber by the total amount of methane, ethane, and propane in the fat oil. As stated above, this inflation amounts to 91 per cent of the molecular quantity of the lean oil, so that for every gallon of oil pumped into the

FIG. 2.



1		2		3		4		5		6		7		8		9	
Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D
C_1	558,468	C_1	521,628	AO	53,209	C_1	36,850	C_1	25,403	AO	2,898	C_1	14,717	C_1	11,405	AO	2,721
C_2	28,041	C_2	21,641			C_2	6,400	C_2	1,516			C_2	5,548	C_2	1,485		
C_3	11,700	C_3	6,320			C_3	5,380	C_3	391			C_3	5,676	C_3	437		
$1C_4$	2,195	$1C_4$	521			$1C_4$	1,674	$1C_4$	32			$1C_4$	1,858	$1C_4$	37		
NC_4	3,123	NC_4	338			NC_4	2,785	NC_4	14			NC_4	3,135	NC_4	26		
$1C_5$	1,294	$1C_5$	1			$1C_5$	1,293	$1C_5$	0			$1C_5$	1,417	$1C_5$	0		
NC_5	795	NC_5	0			NC_5	795	NC_5	0			NC_5	862	NC_5	0		
C_6	1,893	C_6	0			C_6	1,893	C_6	0			C_6	2,000	C_6	0		
F_1	954					F_1	954					F_1	998				
F_2	1,473					F_2	1,473					F_2	1,508				
F_3	88					F_3	88					F_3	88				
F_4	6					F_4	6					F_4	6				
						AO	53,209					AO	65,351				
Total	610,030	Total	550,439			Total	112,800	Total	27,356			Total	103,164	Total	13,390		

10		11		12		13		14		15		16		17	
Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D	Comp.	Mols/D
C_1	4,380	C_1	5,085	AO	13,398	C_1	697	C_1	1,281	C_1	1,199	C_1	722	C_1	2,548
C_2	4,075	C_2	3,427			C_2	2,586	C_2	1,800	C_2	150	C_2	45	C_2	619
C_3	5,130	C_3	1,793			C_3	5,082	C_3	1,577	C_3	59	C_3	16	C_3	671
$1C_4$	1,775	$1C_4$	148			$1C_4$	2,017	$1C_4$	335	$1C_4$	9	$1C_4$	3	$1C_4$	213
NC_4	3,032	NC_4	50			NC_4	3,495	NC_4	425	NC_4	11	NC_4	3	NC_4	361
$1C_5$	1,399	$1C_5$	0			$1C_5$	1,514	$1C_5$	94	$1C_5$	3	$1C_5$	1	$1C_5$	123
NC_5	853	NC_5	0			NC_5	911	NC_5	47	NC_5	2	NC_5	1	NC_5	66
C_6	1,993	C_6	0			C_6	2,048	C_6	46	C_6	2	C_6	1	C_6	106
F_1	998					F_1	1,012	F_1	13	F_1	1	F_1	0	F_1	44
F_2	1,508					F_2	1,510	F_2	5	F_2	1	F_2	0	F_2	35
F_3	88					F_3	88	F_3	0	F_3	0	F_3	0	F_3	0
F_4	6					F_4	6	F_4	0	F_4	0			F_4	0
AO	65,351					AO	81,470	AO	0	AO	0			AO	9,244
Total	90,588	Total	10,503			Total	102,440	Total	5,623	Total	1,437	Total	792	Total	14,030

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absorber the absorbing effect is approximately doubled.

In order to make it possible to distill and condense the desired components in the fat oil stream, it is, of course, necessary to largely remove the methane and ethane before the fat oil finally enters the distillation system proper. This is accomplished by passing the oil through a series of vent tanks represented by the reabsorbers indicated in Fig. 2. Actually the flashing of the fat oil stream is accomplished in a separate vessel outside the reabsorbed shell in each case.

The first flash tank and reabsorber operate at 600 lb. gauge, the second at 200 lb., and the third at about 40 lb. The reabsorbers are provided to control the loss of desired components in the stream of dry gas flashed out of the fat oil stream at each pressure.

In the plant under discussion a large part of the production is separated from the incoming gas after cooling and final pressure reduction of the gas to the main absorber pressure. This separated liquid contains the heavier components of the vapor from the formation, together with the connate water. The water is separated from the distillate and the distillate is then carried through three pressure reductions in the same steps as on the fat oil stream. The gas vented from the distillate stream is conducted to the corresponding reabsorbers for extraction of desirable components along with the gas flashed from the fat oil stream. Quantitative results from this operation are shown in the tables on Fig. 2.

Although the investigation of the effect of absorber pressures between 1000 lb. and 2000 lb. showed only a very small difference in the external lean oil rate for 80 per cent butanes extraction, this does not mean at all that the cost of the absorption plant would not be affected by the operating pressure in the main absorbers. Practically all the factors affecting the cost of the absorption unit are increased by increasing pressure, so that the saving in investment resulting from the reduction of injection compressor horsepower through the use of a high absorber pressure is partially offset by the increased cost of the absorption unit.

The two obvious factors that increase the cost of the absorption unit with increasing pressure are the increasing cost of the main absorbers with their associated piping, and the increase in cost of the high pressure lean oil pumping unit.

In addition to these direct factors, increasing the pressure increases the amount of vent gases that must be handled in the fat oil venting system. This increase in vent gases increases the quantity of reabsorber lean oil required to control the escape of desired components in the vent gases, enlarges the reabsorbers, and increases the amount of recompressor horsepower required to handle the vented gases if no use is available for them at the reabsorber pressures.

In order to arrive at the most economical design of the combination of plant for injection compressors, it is, of course, necessary to make a detailed study of the entire situation surrounding the operation, taking into account all the factors that have been suggested in this discussion. Often this means preparing several complete estimates. Such estimates should take into account not only the initial investment but the probable operating and maintenance costs of the plant and the injection compressors. It has been our experience that operating and maintenance costs per unit of investment are higher for compressing equipment than for the average of the equipment entering into the absorption plant. On account of this the most economical answer for a long-lived project should lean toward those factors that tend to reduce compressor horsepower even to the extent of some degree of increase in the total cost of absorption plant and compressors. It is obvious that a definite answer to this problem in any particular situation is affected by so many factors that it is impossible to do anything but try to suggest what some of them are, as has been done.

● **Limits on absorber pressure.** During the past few years there has been a good deal of discussion among operators and plant designers as to whether there is any practical limit to the maximum pressure at which an absorption plant can be operated. This discussion has been stimulated by the discovery of a few extremely high-pressure fields, where economics for a cycling system might indicate absorber pressures up to 4000 lb.

There does not seem to be any particular reason why an absorption plant could not be operated successfully at such a pressure, except for the fact that all of the equipment would be so special that its cost would be inordinately high.

Another interesting factor that may put a practical limit on absorber pressure is the so-called "retrograde evaporation" of the absorber oil. Careful tests made on this phenomenon several years ago indicated that with an absorber oil having the characteristics listed below the loss of oil through evaporation into the dry gas leaving the absorber would be excessive at pressures much over 2000 lb. The oil used in these experiments had an average molecular weight of 183 and an API gravity of 32.5. The initial boiling point was 300° F., the 50 per cent point 411°F., and the end point 650° F. It was determined by fractional analysis that the following quantity of oil in gallons per thousand standard cubic feet vaporized into the dry gas stream at a temperature of 92° F.

Absorber Pressure	Oil loss in Gal. per M. cu. ft.
1500	0 008
2000	0.02
3000	0.06
4000	0.14

It seems probable that the loss at the higher pressures could be very greatly reduced by using an absorber oil of a considerably higher average molecular weight; however, as far as I know, no tests to determine this have been made under practical operating conditions.

★ ★ ★

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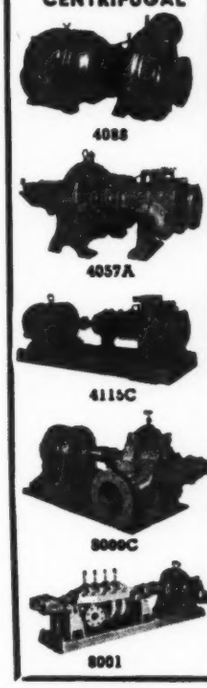

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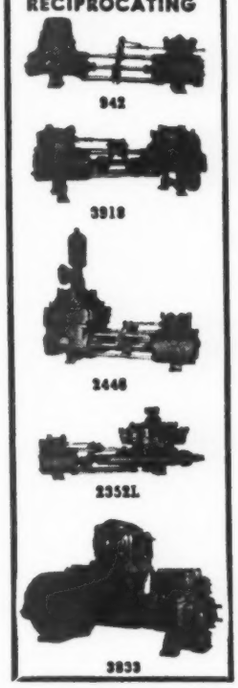

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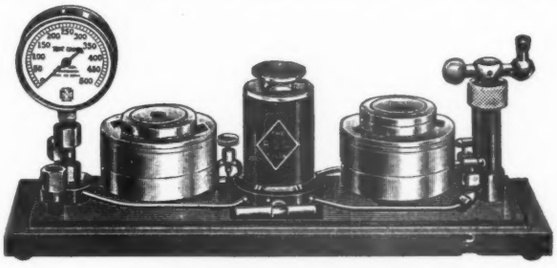

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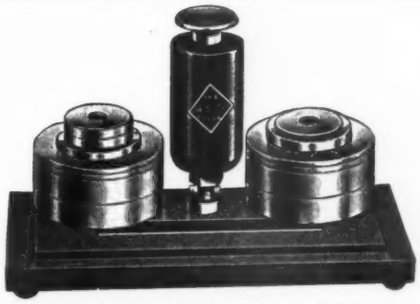

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Cycling Products as Motor Fuel

By **GEORGE GRANGER BROWN**, University of Michigan

EVERY industry or company is in a stronger position when producing and marketing a product suitable for use by the ultimate consumer than when producing a product that requires further processing or blending by some other operator before reaching the ultimate consumer. This principle was recognized and applied in the natural gasoline industry about 20 years ago with most successful results by at least one member of the Association. In that case a finished superior motor fuel based on natural gasoline was sold to the consuming public instead of selling natural gasoline, a "casinghead" as it was then called, to refiners for blending. The success of this program is now a matter of history.

At this time a new product, condensate, is being produced from natural gas in much the same manner as is natural gasoline. The condensate has a wider boiling range and therefore offers more opportunity for diverse products such as motor fuel and kerosine than does natural gasoline. Where it is usually necessary to blend some other material with natural gasoline to produce a finished motor fuel of satisfactory volatility, this is not necessary in the case of condensate. In either case suitable fractionation is required but such equipment is now generally available.

The purpose of this discussion is to consider the production of a superior motor fuel from condensate suitable for distribution to the ultimate consumer.

This would appear to be dependent upon the production of a product of satisfactory octane number as all other requirements can be met easily by proper fractionation or distillation of the condensate to obtain the desired volatility and vapor pressure.

In the accompanying tables four motor fuels prepared from condensate are compared with the character of motor fuel marketed in Chicago and Texas the fall of 1942 and 1944 as reported in the Bureau of Mines Surveys, the results of a private survey of midwest motor fuels, the most volatile fuel in that survey and the new federal specifications for motor fuel.

Inspection of Table 1 indicates that the four condensate motor fuel samples have no difficulty meeting the federal specifications for motor fuel as well as the competition of the winter fuels of 1942 or 1945, although not so volatile as the most volatile fuel marketed last fall. Also, the lead tetraethyl required to bring these condensate motor fuels up to 74 octane is no greater than that required for the average motor fuel sold in the midwest area.

Some care must be used in regard to meeting maximum vapor pressure specifications for grades A and B, but this should offer no difficulty as condensate or cycling plants are usually well equipped with fractionating equipment capable of recovering isobutane, and the front end volatility of the fuel can be adjusted for any reasonable vapor pressure.

Comparison of the data in Table 2 leads to about the same conclusions regarding premium grade motor fuel; however, one of the condensate motor fuel samples L.S.G. is much more volatile than the most volatile motor fuel marketed last fall in the midwest area, either standard or premium grade. It meets the volatility requirements for aviation fuel. This clearly indicates that fuels of the maximum volatility meeting all specifications may be produced from condensate as readily as from any refining operation, a fact thoroughly appreciated by anyone familiar with these operations.

All other specifications such as maximum of 2 per cent residue upon ASTM distillation, 4 mg. gum per 100 ml., 4 hr. stability in oxygen bomb and negative corrosion are readily met by condensate products.

The yield of motor fuel of any particular character from condensate wells depends upon the quality and quantity of the liquid condensate. The curves of Figs. 1, 2 and 3, are directly applicable only to that particular gas from which the data were obtained. They are given here simply to indicate the influence of end point and vapor pressure upon yield and octane number.

From the data available it appears that 74-octane number can be attained with a moderate addition of lead to any condensate motor fuel, and that 80-octane number can be attained without exceeding the maximum of 3 ml. of TEL is indicated in Table 3.

● **Conclusions.** A motor fuel of either standard grade (74) or premium grade (80-octane number) can be produced from condensate wells that meet all re-

*Presented at the 25th Anniversary Convention, Natural Gasoline Association of America, Baker Hotel, Dallas, April 17-19, 1946.

TABLE 1—Comparison of standard grade motor fuels.

	Deg. API	ASTM octane	C. C. TEL	10 per cent over	50 per cent over	90 per cent over	Vapor pressure	Per cents
1. Average, Chicago, 1942	65.7	72.3		116	211	325	11.5	0.071
2. Average, Texas, 1942	62.3	73.2		125	231	331	9.7	0.063
3. Average, Chicago, 1944	62.1	70.2		121	238	347	10.8	0.061
4. Average, Texas, 1944	58.6	70.5		135	252	352	8.1	0.128
5. Average, Mid-West Fall, 1945	62.0	74.5	1.5	128	227	339	9.2	0.057
6. Midwest, extreme, 1945	67.5	77.2	2.6	116	178	324	11.0	0.044
7. Condensate G 91940	67.9	73.6	0.5	120	206	328	12.0	
8. Condensate G 7341	64.9	74.2	1.0	137	223	340	10.0	
9. Condensate W1	66.6			134	204	318	7.7	
10. Condensate CV	70.0	74.7	1.0	120	202	338	10.0	0.026
11. Fed. Spec A,1945		74	3.0	158	266	365	9.0	0.10
12. Fed. Spec. B, 1946		74	3.0	140	257	365	11.0	0.10
13. Fed. Spec. C, 1946		74	3.0	131	248	356	13.0	0.10

TABLE 2—Comparison of premium grade motor fuels.

	Deg. API	ASTM octane	C. C. TEL	10 per cent over	50 per cent over	90 per cent over	Vapor pressure	Per cents
1. Average, Chicago, 1942	66.1	79.1		115	205	315	11.5	0.069
2. Average, Texas, 1942	63.3	78.9		128	220	315	9.3	0.041
3. Average, Chicago, 1944	61.6	75.1		119	233	346	10.7	0.083
4. Average, Texas, 1944	59.5	75.3		132	248	346	8.3	0.107
5. Average, Mid-West Fall, 1945	61.9	79.3	2.4	129	223	332	9.1	0.051
6. Midwest, extreme, 1945	64.4	81.2	3.0	116	195	305	11.6	0.039
7. Condensate G 91940	67.9	82.2	1.5	120	206	328	12.0	
8. Condensate G 7341	64.9	82.8	3.0	137	223	340	10.0	
9. Condensate LSG	73.4	86.0		112	122	280	10.5	
10. Condensate CV	70.0	82.3	3.0	120	202	338	10.0	0.026
11. Fed. Spec. A, 1946		80.0	3.0	158	257	356	9.0	0.10
12. Fed. Spec. B, 1946		80.0	3.0	140	239	356	11.0	0.10
13. Fed. Spec. C, 1946		80.0	3.0	131	239	338	13.0	0.10

FIG. 1

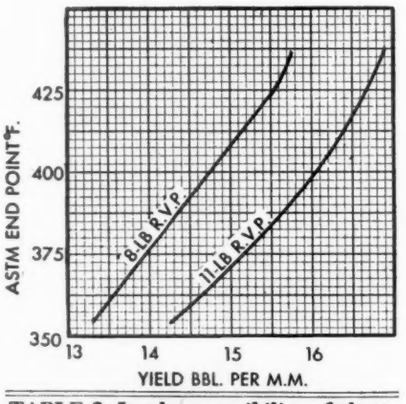

TABLE 3. Lead susceptibility of three condensate motor fuels.

Sample	G 91940	G 7341	C. V.
Clear	..	..	51.5 (63)
+0.5 cc. TEL	73.6	..	..
+1.0	79.1 (78.1)	74.3 (73.1)	74.7 (73.2)
+1.5	82.2	..	..
+2.0	83.6	80.0 (79.3)	..
+2.5	..	..	..
+3.0	..	82.8 (82.4)	82.3 (82.1)

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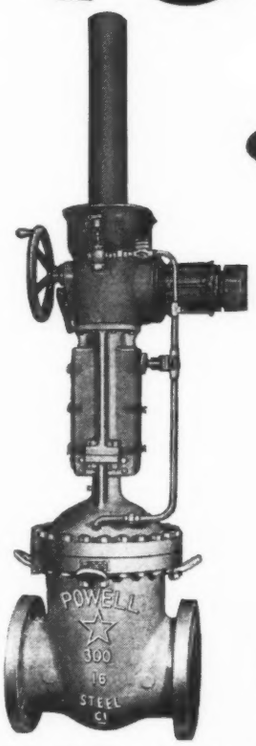

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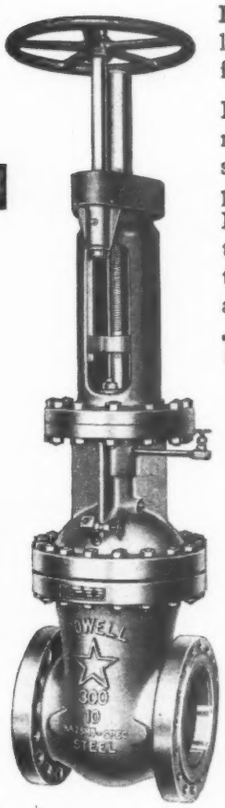

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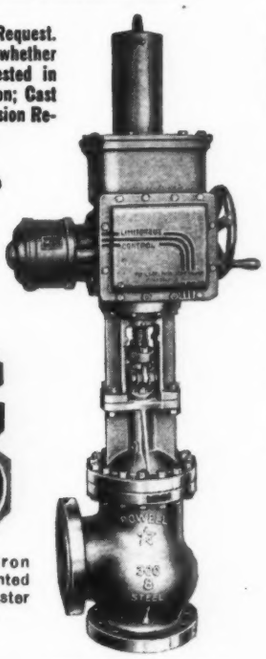

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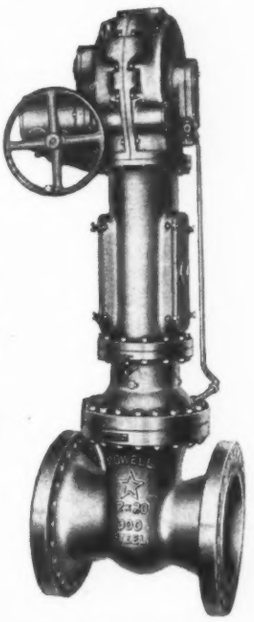

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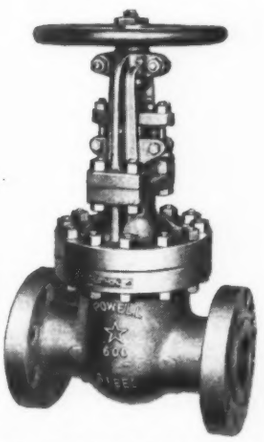
150-pound Stainless Steel O. S. & Y. "Y" Valve.

Class 300-pound Cast Steel Swing Check Valve.



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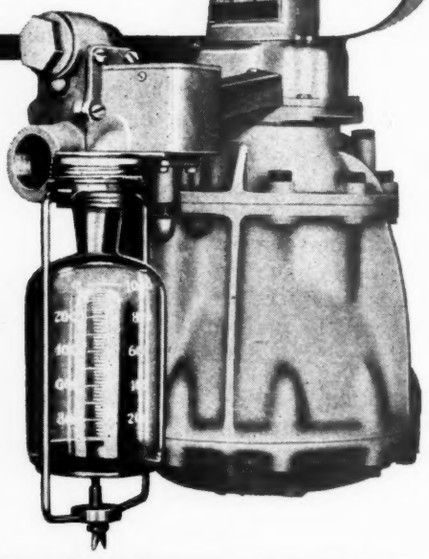

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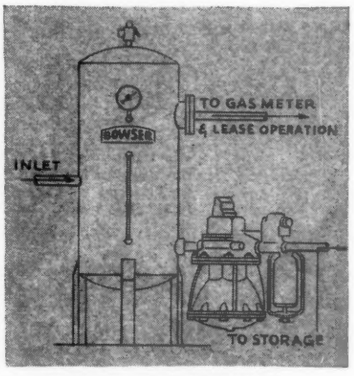

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FIG. 2
For 8-lb. RVP gasolines.

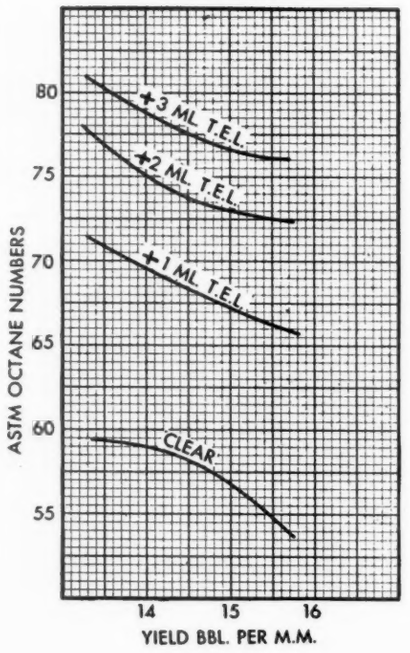
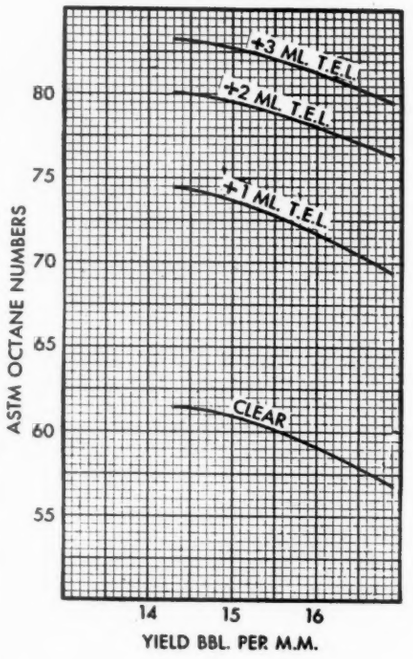


FIG. 3
For 11-lb. RVP gasolines.



quirements of the new federal motor fuel specifications and all the competitive qualities of any motor fuel sold in these grades in the midwest area. Such a fuel is likely to be unusually low in sulphur and free from gum. It is entirely satisfactory for distribution as motor fuel to the ultimate consumer and need not be sold as a blending agent.

● **Acknowledgment.** The cooperation of C. R. Williams of The Chicago Corporation, M. R. Lents of the Cotton Valley Operators Committee, and A. F. Garrett of the Lone Star Producing Company in supplying suggestions and data is gratefully acknowledged. ★★★

Thinking it Through!

[NO. 5 OF A SERIES]

The Proposition **Provision for recycling gas oil should be included in any design for Fluid cat-crackers.**

The Facts Passing any material through a given piece of process equipment more than once at less than the maximum performance level would not, at first glance, appear to be a most economical use of that equipment. However, in cat-cracking, if maximum cracking is attempted in one contact of oil and catalyst, undesirably high percentages of coke and dry gas are obtained in the cracked products.

Experience has proved that for optimum product distribution about half of the fresh feed should be cracked during the first contact with catalyst. Yet experience has also proved that for maximum overall return from feed stock about three-fourths of the average charge should be converted into light products.

Both of these requirements can be satisfied through use of a recycling operation...achieving a high overall yield of profitable products without concurrent waste of feed stock due to over-cracking.

Thus for overall conversion efficiency . . . today and tomorrow . . . provision for recycling the gas-oil fraction is of utmost economic importance.

The Conclusion **There is no substitute for the *best* design.**

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Lighter Hydrocarbons Have Taken on a Lot of Weight*

Liquefied Petroleum Gas in 1945

By G. G. OBERFELL** and R. W. THOMAS†

● **Growth of LPG industry.** The title that we have chosen. "The lighter hydrocarbons have taken on a lot of weight," although somewhat facetious, is one whose inference is of vital importance to every one who has an investment in, or is closely associated with, the liquefied petroleum gas industry. In this discussion frequent references will be made to the liquefied petroleum gas industry, and it may, therefore, be well to accurately define the term. For purposes of this discussion, the term liquefied petroleum gas industry is intended to include all phases of the production, transportation, and distribution of propane, butane, and various mixtures thereof for domestic, industrial, and utility uses. Many remember the early days of the industry when the hard, energetic sales efforts of the industry for an entire year resulted in no more additional users of our products than many of your companies can now sell in a few weeks' time. The contrast of "then" and "now" is indeed interesting. Twenty years ago the problem of the producers, who were interested in marketing liquefied petroleum gas, was primarily the development of a market for large quantities of propane and butane that were being wasted, or were going into extremely low-priced fuel uses. Prior to this time natural gasoline was "weathered", allowing millions of gallons of propane and butane to escape into the atmosphere, and large flares for the purpose of disposing of excess propane and butane burned in gasoline plants and refineries. Before 1930, sale of a single carload of one of the products was considered as sufficient reason for sales managers to rejoice.

Sales promotion, advertising, and technical and equipment advances by the entire industry during the 1930-40 period developed rapid public acceptance of the use of the products and sales showed a marked increase each year, even during the so-called depression years of this period.

By 1940 the industry had definitely reached the "grown up stage" and the years of 1941 to 1945 inclusive can well be considered the years of consolidation. Prior to 1941 a very large percentage of the distributors of LPG for domestic fuel uses had considered this type of use as a "means to an end" in procuring profits from utilization equipment and appliance sales, without seriously considering the potential profit available through planned gas distribution service. During the war period many distributors, rather than depending upon appliance and equipment sales as their major source of profit, concentrated upon making the marketing of liquefied petroleum gas profitable; industries increased their use of the fuels for all types of industrial processes in the manufacture of war materials, and utilities expanded their use of liquefied petroleum gas to augment the capacities of their plants, overtaxed by wartime demands. Almost simultaneously with the consolidation of gas distribution, unprecedented acceptance of the industry by the public has placed the demand for liquefied petroleum gas service for modern, suburban and rural homes on an equal plane with the telephone, radio, and automobile. Careful consideration of these facts certainly justifies the statement that "The lighter hydrocarbons have taken on a lot of weight," and clearly indicates that the industry is at the threshold of its greatest period of expansion.

● **Sources of supply of LPG.** As you all know, liquefied petroleum gases come from three sources: Natural gasoline plants, cycling plants, and refineries. To avoid troubles caused by the condensation of liquid hydrocarbons during the transmission of natural gas from the point of production to places where it is consumed, the heavier hydrocarbons are partially removed. Natural gasoline and liquefied petroleum gases are generally extracted in natural gasoline plants near the gas source. It is customary to separate the extracted material into the desired grade of natural gasoline, and into butane, mixtures of butane and propane, and propane. The greater number of such cuts, the more fractionating equipment required.

A relatively recent source of LPG is from cycling plants, some of which utilize that physical phenomenon known as retrograde condensation. In certain underground reservoirs, many located on the Gulf Coast, high pressure gas exists with little, if any, liquid in the formation. When the gas is brought to the surface and its pressure reduced, sizeable quantities of liquid condense from the gas. The residual gas is then returned to the ground in order to maintain the reservoir pressure as nearly as possible at its original pressure, because reduction in pressure may cause liquid to condense in the formation. This operation of withdrawing gas from an underground reservoir and returning most of it to the formation has given rise to the term "cycling". The liquid material removed contains sizeable quantities of butane and propane which are generally extracted and sold as LPG.

Another source of LPG is from the processing of crude oil in refineries. As a result of the various heating operations performed in refining crude oil sizeable quantities of light hydrocarbons are produced. From these light hydrocarbons LPG can be separated.

Throughout this talk reference is made to the term liquefied petroleum gas. Most of you think of this as butane and propane, although actually a number of additional hydrocarbons may exist in the LPG. In the case of material procured from natural gasoline and cycling plants only the paraffin or saturated series of hydrocarbons generally exists. In the paraffin series we have only one C_3, propane, but two C_4's, butane and isobutane. In the case of refinery LPG, in addition to the hydrocarbons found in material obtained from natural gasoline and cycling plants, varying amounts of olefins (sometimes called unsaturates) occur. Of these the ones of interest are propylene and several butylenes. For simplicity, we use hereafter the terms butane and propane to refer to all the hydrocarbons in the C_3 and C_4 groups.

● **Use of LPG during the war.** During the war large quantities of light hydrocarbons were used in the production of war materials. To fully appreciate the present supply and demand picture of LPG it is necessary to consider briefly the production and consumption of these products during this period. Large quantities of LPG were required in the manufacture of 100-octane aviation gasoline and synthetic rubber components. The production of this aviation gasoline increased from a few thousand gallons per day before the war to more than 20,000,000 gal. per day at the close of the war. Likewise the production of synthetic rubber, which was only minor prior to the war, reached approximately 800,000 long tons during 1945.

Since approximately one-third of the aviation gasoline was produced from LPG, large quantities of these light hydrocarbon gases were required for this purpose. The peak production of aviation gasoline consumed almost 9,000,000 gal. per day or about three times the average quantity of LPG used by our industry in 1945. A large amount of this LPG was obtained from thermal and catalytic cracking operations used in the refining of crude oil.

In the case of synthetic rubber components approximately 50 per cent were produced in 1945 from petroleum products. The two main components were butadiene and styrene, both of which are partially produced from LPG. It is estimated that during 1945 well over 1,000,000 gal. per day, a quantity of LPG equal to more than one-third of the average 1945 daily demand for all purposes of the LPG industry, was used in the production of synthetic rubber components. This demand for these light hydrocarbons has not decreased with the cessation of hostilities but rather has increased and it is expected that this demand will continue for years to come.

*Presented before annual meeting of Liquefied Petroleum Gas Association, Colorado Springs, Colorado, May 27-29, 1946.

**Vice president in charge of research and development, Phillips Petroleum Company.

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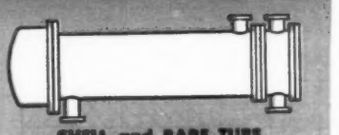

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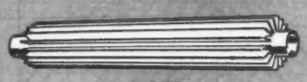

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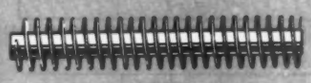
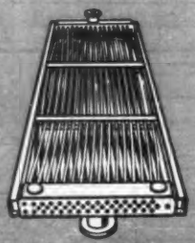
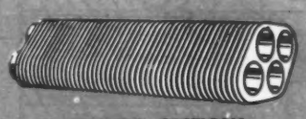
Longitudinal-finned elements for greater heat conductivity



K-FIN
Helical-finned elements for vapors and gases



BENTUBE SECTIONS
with scale-shedding elements for hard or salt water



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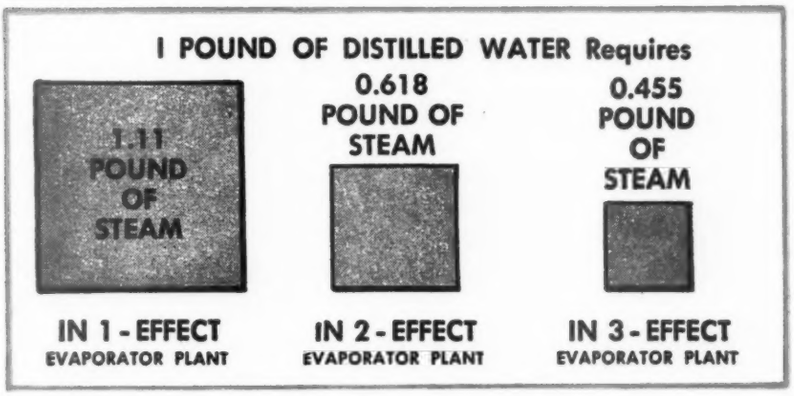
1 POUND OF DISTILLED WATER Requires
1.11 POUND OF STEAM
IN 1 - EFFECT EVAPORATOR PLANT
0.618 POUND OF STEAM
IN 2 - EFFECT EVAPORATOR PLANT
0.455 POUND OF STEAM
IN 3 - EFFECT EVAPORATOR PLANT

A more complete explanation of multiple effect evaporator systems, and other factors involved in the decision of the most economical method of producing pure distilled water or vapor for individual plant requirements — are fully discussed in Bulletin 364 which will be sent without obligation on request.

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It is evident that the war requirements for light hydrocarbons in the production of aviation gasoline and synthetic rubber increased from virtually nothing to between three and four times the quantity being used by the LPG industry. These hydrocarbons were obtained by increasing the quantity of crude oil being refined, through extensive use of new and modified cracking facilities, installation of new natural gasoline and cycling plant facilities, and by installing new separation equipment for removing the light hydrocarbon gases from gas streams that were heretofore sent to carbon black plants, used in plant fuel gas systems or in a few cases wasted. With the termination of hostilities the demand for light hydrocarbons in the production of aviation gasoline has greatly decreased. The requirement for the production of synthetic rubber components, however, has increased because of the scarcity and high cost of ethyl alcohol, the principal alternate raw material. An interesting side light is that the quantity of crude oil being refined today is only slightly less than the quantity which was being refined during the war.

Present demand for LPG. The sale of any material is with few exceptions to that market where it will command the greatest profit; LPG is no exception to this rule. When LPG was introduced in sizeable quantities it was more or less a secondary product, its production cost being its fuel value plus the cost of separating and purifying it. Today, however, conditions have changed greatly. Instead of being used only for fuel purposes, LPG is being demanded in large quantities by several other markets that command higher prices.

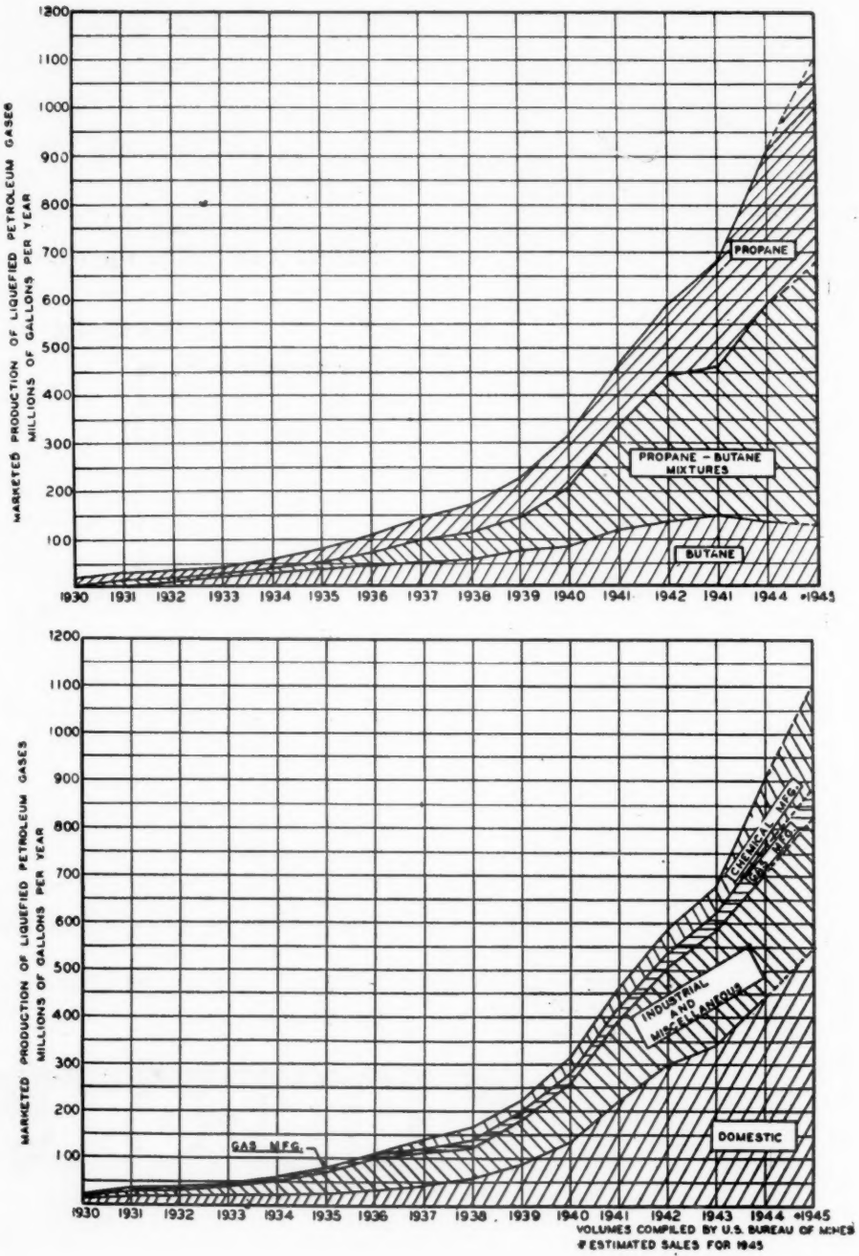
Some of the most important markets in which LPG is used in large quantities are: Motor gasoline blending, refining processes (polymerization, alkylation, etc.), synthetic rubber components, chemicals, carbon black, and plant fuel.

Most of you are aware of the fact that sizeable quantities of butane are blended in motor gasolines, the quantity depending to a great extent upon the season of the year, with greater quantities being so used during cold weather than during hot weather. Before the war a yearly average of 6 per cent of the gasoline volume was butane. With the advent of increased cracking facilities the resulting gasoline generally has a higher vapor pressure than that produced before the war. This results in less butane being required in cracked motor gasoline. Gasoline produced by the operation of alkylation units will have, as a rule, a lower vapor pressure than that produced by cracking. This lower vapor pressure is increased by the addition of greater quantities of butane. Although it is expected that some alkylation units will be operated for the production of motor gasoline, it is rather difficult to estimate the future consumption as the process is rather expensive unless low cost isobutane and butylenes are available. While it is expected that less butane will be required per gallon of gasoline sold than before the war, nevertheless approximatly 1½ times the quantity of LPG used in 1945 by the LPG industry still will be required in motor fuel blending with the seasonal demand coinciding with the maximum LPG market demand. During the war sizeable quantities of propane were substituted for butane in the blending of motor gasoline. This substitution is not normally practiced except as an expedient. Therefore, there is little commercial possibility of substituting another hydrocarbon for butane. When blended with motor gasoline, butane is worth slightly more than motor fuel prices, which are considerably above current LPG prices.

Sizeable quantities of butane have been and will continue to be used for the synthesis of motor gasoline. If an octane number race takes place in the marketing of motor gasoline, it is possible that a number of alkylation units will be operated in order to produce high octane number motor gasoline. The refinery alkylation unit is a means whereby isobutane and C_3, C_4 and/or C_5 olefins are converted chemically into a high quality motor or aviation fuel ingredient. It is rather difficult to estimate what the demand for C_4 hydrocarbons would be for this purpose. It is possible that between 2,000,000 and 4,000,000 gal. per day of C_4's will be required for the post war program of synthesizing motor fuel and aviation ingredients.

It is not expected that the C_4 demand in the production of synthetic rubber components will cease for some time. It is estimated to be in the neighborhood of 700,000 gal. of C_4 hydrocarbons per day. Propane is used extensively as a starting product for the production of ethylene

Graphs showing growth of liquified petroleum gas industry.



• *These aren't ordinary tank cars at all, for if they were they'd arrive at their destination empty—perhaps blown up. They are really "pressure vessels on wheels", designed to keep these gases liquified while in transit by maintaining them under pressures up to 300 lbs. or more.*

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Yes, extra value in WeldELLS . . . . and here's why. To make the best Welding Fittings that can be made you have to know two important things:

1. What constitutes "the best" design.
2. How to make the metal go where you want it to go in forming so as to provide that design in the finished product.

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WeldELLS alone combine these features:

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for synthesis of styrene and may continue at about the rate of 700,000 gal. per day.

Light hydrocarbons, especially propane, are used in the production of chemicals. The more desirable olefinic feed stock as a rule is obtained from refineries, resulting in many new chemical plants being located adjacent to refineries. The quantity of light hydrocarbons being used for the production of chemicals is increasing steadily but still represents only 20 to 50 per cent of the light hydrocarbons used by the LPG industry.

With the large wartime expansion of the synthetic rubber industry, new types of carbon blacks were required and great increase in production of conventional blacks, coupled with some modification of their properties was necessary. Carbon black is very essential to the manufacture of auto and truck tires. The introduction of butane and propane in residue gas going to existing plants increased the carbon black production. As many carbon black natural gas contracts require a minimum B.t.u. or minimum carbon black yield per cubic foot of residue gas burned, butane and propane cannot be extracted beyond a certain point.

Large quantities of heat are required around natural gasoline plants and refineries. It is the usual practice to pipe residue gas produced in these plants to points where it can be utilized to liberate the required heat. If butane and propane are removed from this residual gas the resultant supply may be insufficient to meet the heating requirements, in which case natural gas or oil must be substituted, giving the extracted LPG a value equivalent to the substituted natural gas or oil plus the additional processing costs necessary to secure a marketable LPG product.

● **Present resources and present production of LPG.** It was estimated that during the war the average annual resources of C_3 and C_4 hydrocarbons were more than ten times the total 1945 consumption of the LPG industry. When it is realized that the consumption of the LPG industry increased tenfold in the last ten years (1930 — 106,652,000 and 1945—1,100,000,000 gal.) it is readily apparent that the LPG industry will have to grow enormously before it makes noticeable inroads into the potential LPG reserves. In fact, it hasn't made a dent yet. It should be remembered that a large amount of the potential LPG will have to be separated from existing streams and treated in order to produce a product that will meet purchase specifications. This additional separation and treatment would increase the cost of this added volume to a point where it will not be possible to obtain it at the current LPG prices. This will have a tendency to cause a gradual increase in average cost of LPG. This increase is expected to continue until the price of motor fuel has been reached, particularly with respect to butane.

One of the sources of supply that is rapidly growing is from cycling plants. Also, a number of new natural gasoline plants are being erected. The main disadvantage with natural gasoline plants is that frequently their LPG production is so small that it is difficult to justify the installation of the necessary separation equipment. In the case of cycling plants, however, the volume is large enough that LPG manufacturing facilities can be justified. Because of the place advantage of LPG produced at the point of use, all needed refinery LPG is used to meet the local demands of the refiner before procuring shipments from natural gasoline or cycling plants. Some refineries will have an excess over their own requirements and this material is potentially available to the LPG industry at a price.

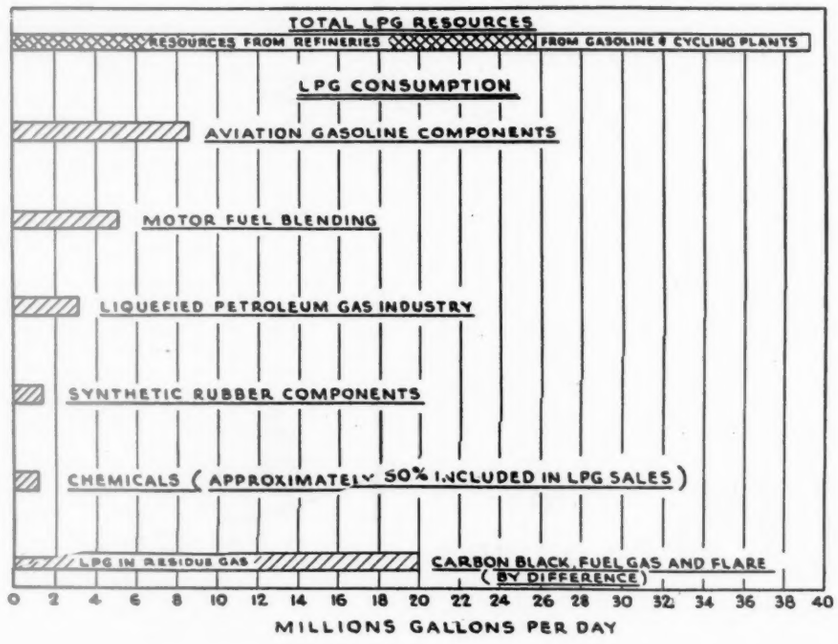
● **Future supply of LPG.** As previously indicated, the supply of liquefied petroleum gas is derived from two distinct sources: That from cycling and natural gasoline plants that is only partly related to crude oil production, and that from refining of crude oil. It is not expected that the quantity of crude oil processed in the United States will decrease appreciably below its present level. Indications are for some increase in crude runs as the availability of new automobiles increases. In fact, our national motor gasoline demand for the first two months of this year is higher than for a similar period in 1941 and more than 20 per cent greater than the first two months of 1945. We have no reason to expect a diminishing supply of LPG from refineries. Likewise, with the increased demand for natural gas it is expected that greater quantities of LPG will be produced at cycling and natural gasoline plants.

A recent development that enters the future LPG supply picture is the so-called Fischer-Tropsch process, or variations thereof, which use natural gas as raw material for the production of heavier hydrocarbons. The production of motor gasoline and other petroleum products by this method may yield sizeable quantities of butane and propane. Therefore, installations of this process for the production of petroleum products are not expected to diminish the overall supply of LPG.

The quantity of butane that will be available for use as such or in mixtures with propane by the LPG industry will be dependent directly upon the price offered. Our industry is in competition with the butane requirements for the synthesis of aviation and motor gasoline, production of synthetic rubber components, blending of motor gasoline, and chemical manufacture. These competitive uses can afford to pay more than current LPG prices for much of their requirements. Therefore, the quantity available for use by the LPG industry will be the difference between the demands of the higher price markets and the production. Until the LPG industry is willing to pay motor fuel prices for its butane, the supply for LPG uses will be seasonal and limited. Far-sighted marketers will not depend on butane for their long term future requirements unless they are convinced of the profitability of paying a premium over the propane market. So practically everyone is now purchasing transportation, storage, and utilization equipment for propane because of this long term trend.

● **Investment considerations.** The requirements of industries competing for propane and butane and the large volume sales of the liquefied petroleum gas industry itself have created problems of production, transportation, and storage. The producer or producer-marketer and the distributor or direct user because of these mutual problems are more closely associated than ever before. Liquefied petroleum gas is now a co-product and

Estimated average daily resources and consumption of LPG in first 6 months of 1945.


TOTAL LPG RESOURCES
RESOURCES FROM REFINERIES
FROM GASOLINE & CYCLING PLANTS
LPG CONSUMPTION
AVIATION GASOLINE COMPONENTS
MOTOR FUEL BLENDING
LIQUEFIED PETROLEUM GAS INDUSTRY
SYNTHETIC RUBBER COMPONENTS
CHEMICALS (APPROXIMATELY 50% INCLUDED IN LPG SALES)
LPG IN RESIDUE GAS
CARBON BLACK, FUEL GAS AND FLARE
(BY DIFFERENCE)
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40
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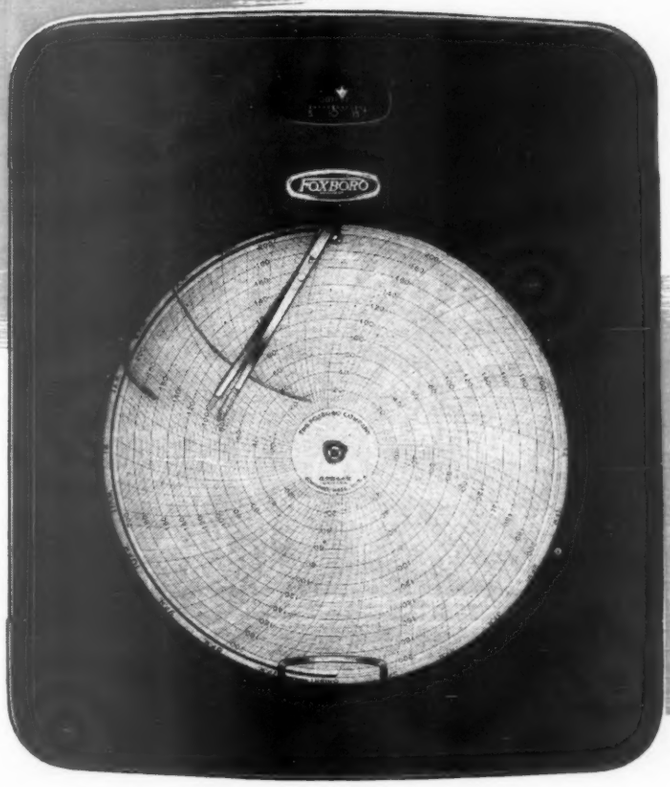

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* Reg. U. S. Pat. Off.

not a by-product in most producing plants. Cost of butane and propane production has steadily increased. Since the production of LPG is a continuous operation, sale of liquefied petroleum gas must be made on a regular basis with almost constant daily shipments. Failure to move the products as they are produced can only result in increased cost. Meeting the industry's peak demands at present price levels is becoming increasingly more difficult for producers, transporters, and marketers.

Transportation, that all important link between the producer and the distributor or user, has become a very important factor in the industry. At the present time there are approximately $17,000,000 invested in the special tank cars required to transport butane and propane, exclusive of the pressure cars in butadiene and chemical services, and exclusive of the millions of dollars invested in LPG transport and tank trucks. Based on the present efficiency of movement of cars, an average investment of approximately $5,000 in tank cars is required to deliver one car per month to a distributor.

● **Seasonal load variations.** Giving serious consideration to the major factors of production and transportation, it is clearly evident that if the liquefied petroleum gas industry is to maintain its present position economically, seasonal peaks in the deliveries of fuel must, to a great measure, be eliminated. A seasonal peak occurs during the winter months of November, December, January, and February, caused in part by a high demand for winter space heating requirements in the South. The transportation problem which results is further exaggerated by a general slow-up in transportation in the North. Possibilities for improving the situation include:

1. Increased domestic consumer's storage, especially where consumer uses fuel for winter heating.
2. More LPG storage at distributor's bulk plant and at industrial and utility plants.
3. Active sales promotion of summer uses.

Ample fuel storage is the only assurance of an adequate LPG supply at all seasons of the year.

Active sales promotion of summertime uses of propane and butane offers opportunity for increased profits for the distributor. Summer loads are attractive for the reasons that transportation costs are lower during the summer months, working conditions and labor efficiency are greater at this time and, consequently, a greater margin of profit can be realized on fuel sales.

Possibilities for increasing summer activities include flame cultivation, weed burning, farm product dehydration. and motor fuel use in farm tractors and irrigation power units. Flame cultivation of cotton, sugar cane, and other row crops will consume large volumes of propane and butane during 1946 and this will undoubtedly expand many times during 1947 and 1948. Considerable research and development work has already been carried out by the LPG industry with manufacturers of farm tractors and power units to provide prime movers factory equipped for efficient, economical use of butane and propane; 1947 should see several thousand factory equipped liquefied petroleum gas units in operation. Dehydration of alfalfa, sweet potatoes, and other farm products will require large volumes of LPG in future years.

● **Conclusions.** In conclusion the preceding remarks are summarized:

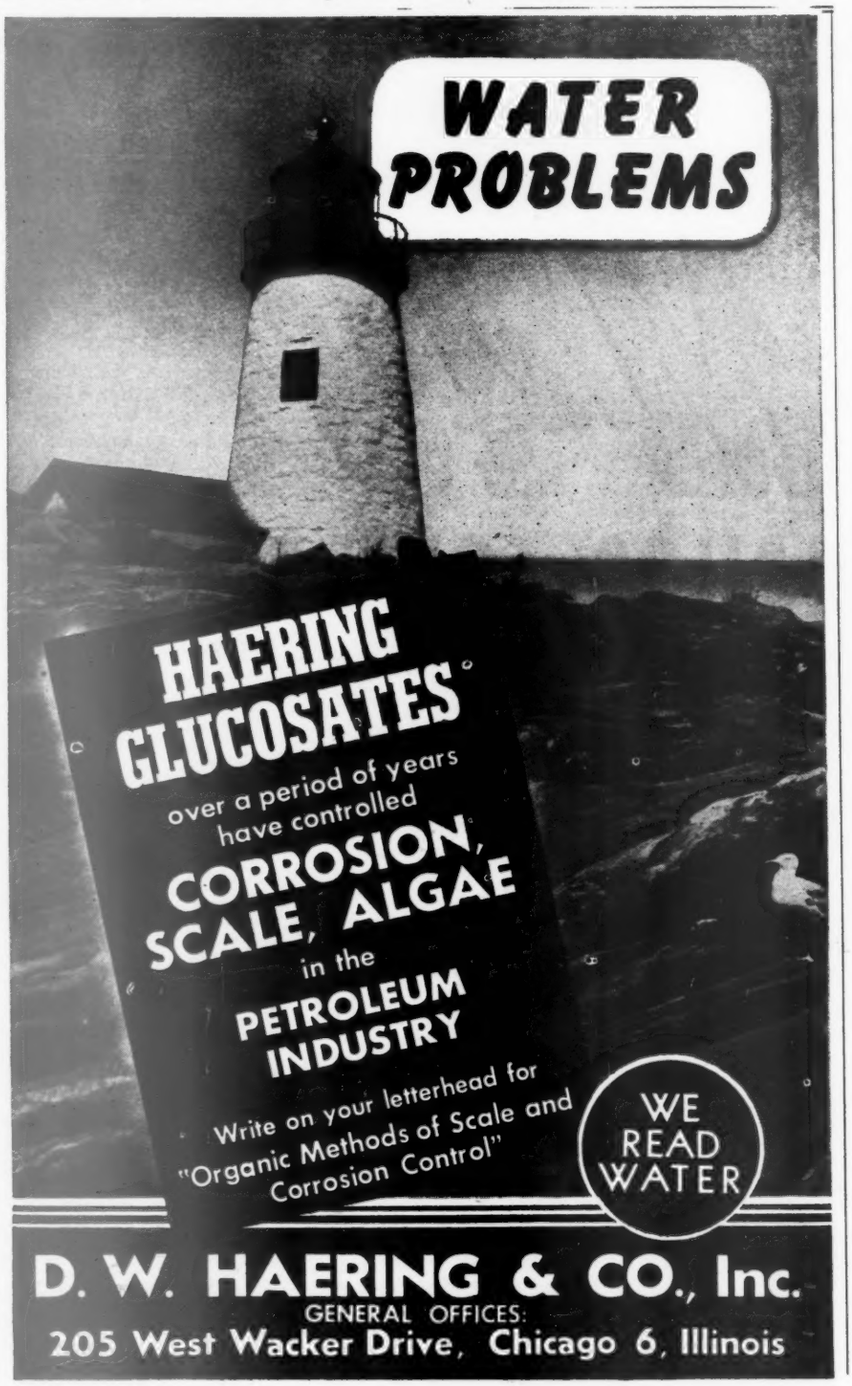
(1) The industry's initial rapid growth has been followed by a period, during war years, of very healthful consolidation.

(2) Growth of the industry, particularly for domestic uses, in 1947 and 1948 should far exceed any previous two-year period.

(3) There is ample supply of butane and propane for the requirements of motor fuel, aviation gasoline, synthetic rubber, and chemical industries, over and above the requirements of the LPG industry. In fact, the potential supply far exceeds present demands.

(4) Increased cost of production facilities and competition from other industries for the products will, over a period of time, probably increase the cost of propane and certainly increase the cost of butane to the LPG industry.

(5) Leveling out the winter-summer ratio is the industry's best assurance of continued satisfactory supply and will serve to delay price increases brought on by competitive industries. ★★★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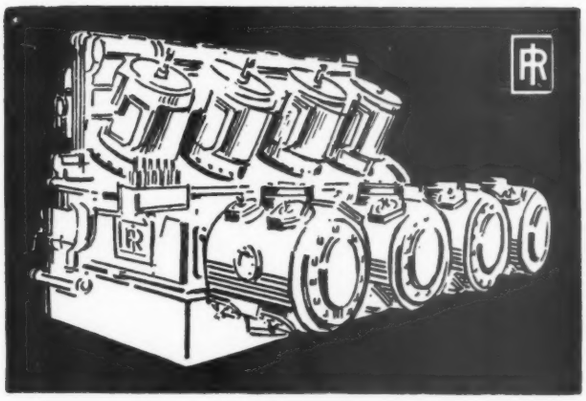

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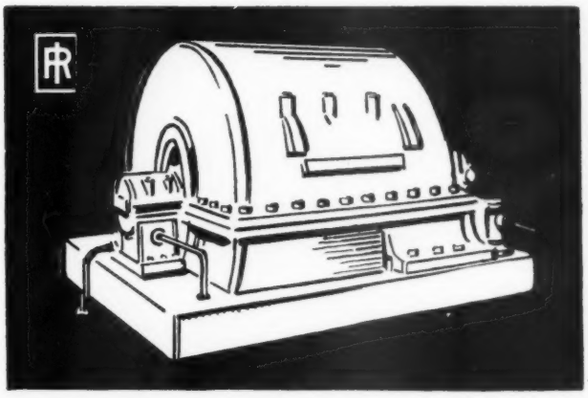

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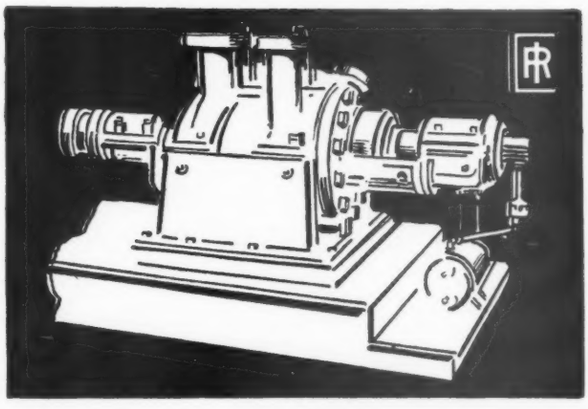

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A Fluid Catalytic Cracking Unit for the Smaller Refiner*

By DAVIS READ†

Universal Oil Products Company

THE majority of catalytic cracking units constructed during the war had a nominal capacity in excess of 10,000 bbl. per day, although a number of smaller units of 4000-5000 bbl. per day capacity were also operated very successully to produce aviation gasoline components. The smallest fluid catalytic cracking unit, having a capacity of 2600 bbl. per day, has been in operation for nearly 2 years and is presently producing motor fuel. A considerable amount of development work was done on each of these units for the purpose of increasing throughput and improving the efficiency of operations to produce the maximum amount of aviation gasoline components. The data thus obtained have permitted a revision of the original factors used in the design so that it is now possible to build less expensive, more efficient equipment to produce high quality motor fuel.

Davis Read

The 2600 bbl. per day unit took advantage of revised design factors to some extent and incorporated several features that have proved advantageous in the construction of small units. The present simplified UOP design has been a logical development of the fluid cracking process, as illustrated in Fig. 1. These flow diagrams, which are drawn approximately to the same scale, show briefly the stages in the development of the present simplified unit.

● **Development of mechanical design.** The left-hand portion of Fig. 1 shows the typical downflow type of construction that was embodied in many of the smaller (5000 bbl. per day) fluid cracking units operated during the war. The raw oil enters the system at the base of the regenerated catalyst standpipe. The heat in the catalyst vaporizes the oil and the mixture of oil vapors and catalyst flows upward through a riser into the reactor. The vapor velocity is such that the catalyst suspended in the oil vapors falls back and forms a dense layer on the grid plate. The term "downflow" originates from the fact that the catalyst partially separates from the oil by gravity and flows downward out of the bottom of the vessel. The oil vapors pass through this dense catalyst bed where the cracking reaction takes place and the cracked products then pass through a centrifugal separator where entrained catalyst is removed. The vapors then pass to a fractionating column where the desired products are separated. As the fine catalyst powder used in these plants cannot be entirely retained by the cyclones, it is necessary to return the catalyst carried into the fractionator to the cracking section by recycling tower bottoms or slurry oil.

The spent catalyst leaving the reactor is stripped by steam to remove entrained oil vapors and then descends through a standpipe to the point where air is introduced. The air required for burning the carbon formed in cracking carries the spent catalyst up through a long riser into the regenerator. Both the riser and the regenerator are lined with refractory brick. The catalyst separates by gravity, settles back into a dense fluid phase, and flows downward through a standpipe to meet the incoming raw oil. The products of combustion pass out through cyclones to remove entrained catalyst, through a waste heat boiler and finally through a Cottrell precipitator where most of the remaining catalyst is recovered. The fines recovered from the Cottrell are returned to the regenerator.

Thus it is seen that there are 3 principal flowing streams in the fluid process:

1. The oil passes through the reactor to the fractionator.
2. The air for regeneration of the catalyst passes once through the regenerator.
3. The catalyst circulates within the system.

The catalyst circulation rate depends upon the pressure differential across the slide valves. The higher pressure above the slide valve is the sum of the pressure in the top of the vessel and the static head created by the dense catalyst in the vessel and standpipe. In this type of unit the regenerator pressure is fixed by the back pressure on the outlet line at 1 to 4 lb. per sq. in., depending upon whether a restriction grid is installed in this line. The pressure above the slide valve then depends largely on the catalyst density in the vessel and standpipe. The pressure below the slide valve is low because of the lower density of air, or vapors, and catalyst in the riser.

It was found that the catalyst finally developed and used during the war increased considerably in density during service; consequently, the pressure drop available for causing circulation was much greater than the design basis. As more pressure drop was available than that required for the specified cracking operation in the original downflow units, it follows that the static head or overall height of the regenerator can be decreased, thus decreasing the installation cost. For the smaller units it is also entirely feasible to install a pressure control valve in the regenerator outlet and operate this vessel under pressure, again decreasing the height of the vessel above grade. These two features were incorporated in the design of the 2600 bbl. per day unit.

The center section of Fig. 1 shows a flow diagram of this modified design. The reactor pressure is approximately 9 lb. per sq. in. in this modified unit and the regenerator pressure is about 10 lb. per sq. in. Aside from permitting a decrease in the overall height of the regenerator, the higher regenerator pressure results in an improved carbon burning rate. Even though the overall height was decreased from 180 ft. in the original downflow design to 100 ft. in the modified design, the available driving force is still more than required for good catalyst circulation. This unit has circulated catalyst successully with 2 to 3 lb. per sq. in. pressure drop across each slide valve, although the available pressure drop is much greater.

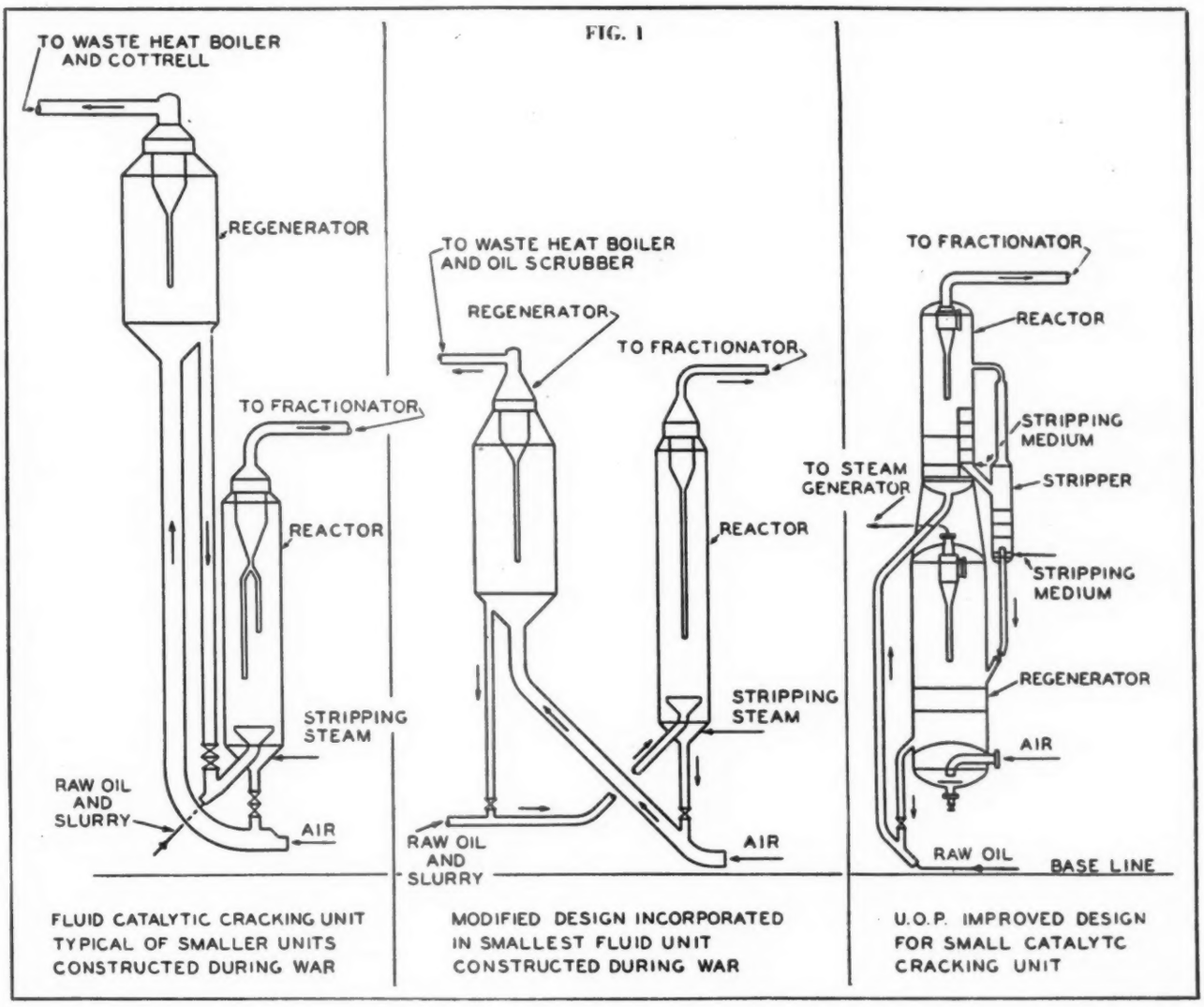
Several other improvements in design for smaller units were incorporated in the 2600 bbl. per day unit. The Cottrell precipitator was replaced with an oil scrubber, which removes the catalyst fines from the regenerator gases almost completely. The risers do not contain refractory lining, which has caused some difficulty in other units.

The right-hand sectoin of Fig. 3 illustrates the newer fluid catalytic cracking unit design, which includes the improvements previously described, as well as

*Presented before Western Petroleum Refiners Association, Fort Worth, Texas, March 26, 1946.

†Davis Read, a member of the commercial development department of Universal Oil Products Company, was graduated from Purdue University in 1936 with a B.S. degree in chemical engineering. Upon graduation he joined the Reilly Tar and Chemical Corporation of Indianapolis, leaving in 1937 for a year of study at the University of Michigan, leading to an M.S. degree in chemical engineering. Read joined Universal in 1938. His work with this company has been in various phases of research and development, including pilot plant investigations.

FIG. 1



several additonal features that increase efficiency. As commercial tests show that it is entirely feasible to operate with a slide valve pressure drop of 3 lb. per sq. in., the next logical step is to lower the larger regenerator vessel still further. This permits the regenerator to be placed below the reactor and in smaller sizes the reactor can be supported by the regenerator, thus eliminating the heavy structure required for support in the older design. The overall height of a 3300 bbl. per day unit is approximately 125 ft.

Briefly, the flow through this unit is as follows: The oil feed is charged as a liquid at the base of the reactor riser, hot catalyst from the regenerator enters the riser at the point of oil injection, supplies the process heat requirements and is transported upward by the vaporized oil into the reactor. Spent catalyst is continuously withdrawn from the upper part of the reactor dense phase to hold a level in the reactor and passes downward through the stripping section into the regenerator. Three zones are available for stripping in this design. The stripping medium is injected at the bottom of both the internal and the external strippers. Additional stripping of the spent catalyst is obtained in the upper section of the regenerator where the bulk of the flue gas from the combustion of coke in the lower sections contacts the incoming catalyst. The catalyst passes downward through the regenerator countercurrent to the air supplied at the bottom for regeneration.

Regenerated catalyst flows from the lower section of the regenerator to the reactor riser at a rate controlled to maintain a constant reactor temperature. The regenerator flue gas is vented to the atmosphere through an internally mounted cyclone separator that recovers entrained catalyst. The reaction products pass to the fractionator through an internally mounted cyclone separator that recovers entrained catalyst and returns it to the catalyst bed. A comparison of the 3 diagrams in Fig. 1 will show that the principle of catalyst circulation from one vessel to another by transfer from a zone of high density through a zone of low density is the same in all 3 units.

It has been demonstrated that the installation of distribution plates improves the efficiency of contacting of oil and catalyst in the reactor resulting in a higher liquid recovery and less gas formation. The installation of additional grid plates in the regenerator and stripper results in an improved carbon burning rate and stripping efficiency with a decrease in operating costs. These improvements have been incorporated in the new design.

By building the regenerator below the reactor it is now possible to pass the air for regeneration countercurrent to the flow of catalyst. With the countercurrent flow and staging of the regenerator with grid plates the oxygen content of the outlet gas can be reduced to ½ to 1 per cent, whereas in previous units 2 to 3 times as much unused oxygen normally escapes from the regenerator. This feature of the new design was not possible in the older units. A detailed discussion of these improvements in efficiency, which have been incorporated in the new design, has been previously given in the literature[1].

● **Control of operations.** Fig. 2 illustrates the system used for controlling the operation of the simplified unit. The reactor temperature controls the flow of catalyst through the regenerated catalyst slide valve and the reactor level controls

[1]Anderson and Sterba, *Oil & Gas Journal*, V. 44, pp. 77-80, 84-88. *The Petroleum Engineer*, December, 1945, pp. 62-69.

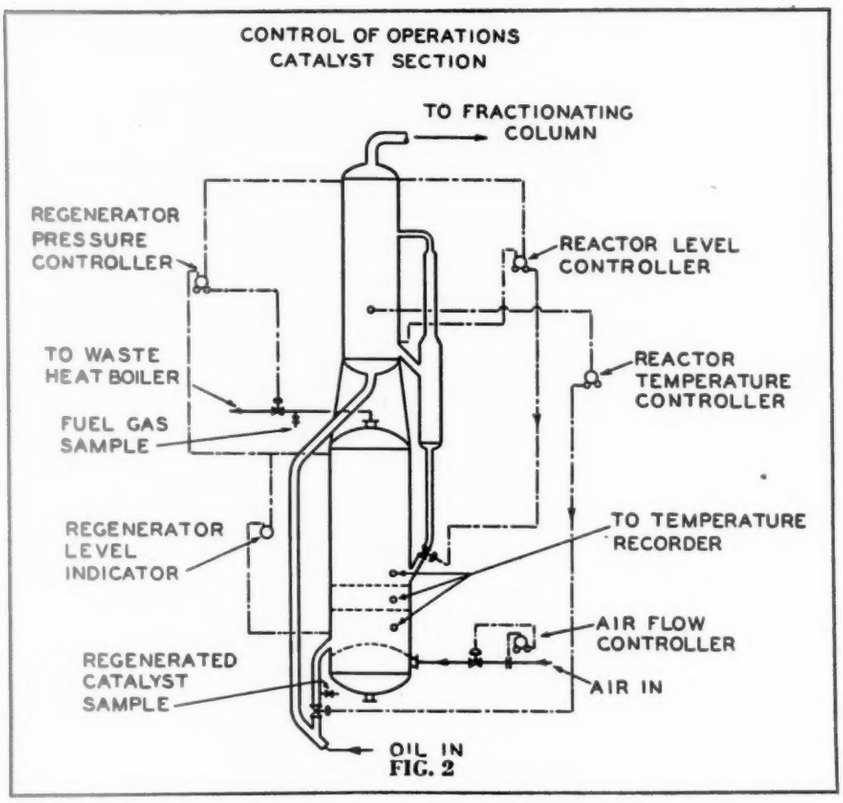


FIG. 2

the flow through the spent catalyst slide valve. The reactor pressure is held constant by the gas compressor and the regenerator pressure is held constant by the rate of release of flue gas, with the valve in the flue gas line controlled by the pressure difference between the reactor and regenerator. This method of control is used on the 2600 bbl. per day unit and has several advantages. The pressure drop across the slide valve does not vary appreciably, for both the vessel pressures rise and fall together in the event of surges in either the air or gas compressors. The catalyst flow is very uniform and responsive to changes made in the instruments. The cracking reaction, as measured by the per cent yield of cycle stock or by the gas rate, is controlled at constant throughput by varying the reactor level or temperature. An increase in either the reactor level or the temperature increases the conversion. In order to control the burning reaction an analysis of the regenerator outlet gas stream is obtained and the carbon content of the catalyst is determined periodically. The regeneration is then controlled by varying the air or carbon production rate.

● **Catalysts.** The simplified unit can utilize either synthetic or natural catalyst. In its most simple design synthetic catalyst having a microspherical form is used. Due to the spherical shape of the particle and its greater strength, as compared with the ground powdered catalysts used during the war, this catalyst has very low erosion and attrition rates. In addition, the MS catalyst is much more uniform in particle size than the ground catalyst. This permits the design of this unit without the use of secondary recovery equipment such as a Cottrell or oil scrubber or slurry pumps. Two synthetic microspherical catalysts composed of either silica-magnesia or silica-alumina are available. As the natural catalyst is lower in cost per pound than either of the synthetic catalysts, its use must be considered. When natural catalyst is used, however, secondary recovery equipment must be added to the MS unit. This equipment consists of an oil scrubber or Cottrell to recover the fines from the regenerator outlet gas and pumps to return catalyst slurry from the fractionator to the reactor.

Economic consideration of market requirements and operating costs will govern the choice of catalyst. The silica-alumina catalyst gives the highest octane number and lowest gasoline yield, whereas considerably more gasoline having a lower octane number is produced from the silica magnesia catalyst. The natural catalyst gives a gasoline yield and octane rating intermediate to the values obtained by the 2 synthetic catalysts.

The catalytically cracked gasolines produced from each catalyst have blending octane numbers considerably higher than their rated values when blended with straight run gasoline. This blending value varies with the quality of the straight run and per cent of catalytically cracked gasoline in the blend. For example, a catalytic gasoline having an ASTM octane rating of 81 would have a blending octane rating of 89 ASTM when blended with 70 per cent straight run having a 53-octane rating. The research method blending value of the catalytic gasoline would be approximately 110 in this example.

● **Methods of processing.** The flexibility of the fluid cracking process has been well demonstrated by units now in operation. Various charging stocks, including naphtha, kerosine, gas oil, and topped crude have been processed commercially at temperatures ranging from 800-1000°F. in either once through or recycle operation. This same degree of flexibility can be obtained in the improved MS unit.

With the present limited gasoline and maximum fuel oil demand the operation of a catalytic cracking unit at extremely high conversion does not appear advantageous. To meet present market demands a refiner would, therefore, probably operate a fluid catalytic cracking unit at an intermediate conversion level of 55-65 per cent to produce both gasoline and burner oils. As the cracking reaction can be controlled by varying the amount of catalyst in the reaction zone, it is possible to return a part of the cycle stock to the reactor without reducing the net yield of cycle stock. By reducing the level of catalyst in the reactor and recycling a part of the cycle stock, the conversion per pass is decreased. This operation increases the

TABLE 1

Comparison of once-through and recycle operation.

Fluid catalytic cracking Mid-Continent gas oil
65 per cent conversion
Natural catalyst

Yields, vol. per cent	Once-through	1.67 CFR
Debutanized gasoline, vol. per cent	48.9	50.5
Cycle stock, 460°F +, vol. per cent	35.0	35.0
Butylenes, vol. per cent	5.8	6.5
Butanes, vol. per cent	7.4	5.5
C_3 and lighter, wt. per cent	6.6	5.4
Debutanized 400°FFP gasoline		
Octane No. ASTM (F-2)		
Clear	80.3	79.2
+3 cc. TEL	86.5	85.5
Octane No. Research (F-1)		
Clear	90.8	90.8
+3 cc. TEL	96.5	96.5
Cycle stock, 400°F +		
Gravity, deg. API	26	28

TABLE 2

Estimated normal utility requirements 2000 bbl. per stream day fluid catalytic cracking unit.

Basis:
60 per cent conversion Mid Continent gas oil
Catalyst section and fractionator
Through gas compressor

1	Steam	Lb. per hr.
	Required (150 lb. per sq. in.)	
	Pumps	3000
	Stripping	1000
	Total	4000
	Produced (150 lb per sq. in.)	
	From column bottoms steam generator	5500
	Net produced	1500
2	Electricity	kw.
	Lights and power	15
3	Fuel gas	MM B.t.u. per hr.
	Required	
	Gas compressor	3
	Air compressor	5
	Total	8
	Produced	
	After polymerization	31
	Net produced	23
4	Cooling water (85°F. max. inlet)	
	Main condenser	250
	Gas compressor cooling	150
	Cycle oil coolers	100
	Total	500

gasoline and butylene yield and decreases the yield of dry gas and butanes, as shown in Table 1. The decreased conversion per pass reduced the ASTM (F-2) octane numbers of the debutanized gasoline, but had no indicated effect on the Research (F-1) octane ratings at the conversion and temperature level under which these tests were made. Note that the cycle stock became lighter in gravity in going from once-through to recycle operation at a constant conversion or yield of cycle stock.

As previously described, the heat required to vaporize the raw oil in the fluid catalyst process is supplied largely by direct heat transfer between the raw oil and the hot regenerated catalyst. The simplest design of the new unit is, therefore, based on processing a given amount of liquid feed in once-through operation at conditions under which there is a balance between the heat released in regeneration and the heat absorbed in processing.

A unit designed for once-through operation can, of course, recycle at a lower raw oil throughput than the maximum capacity obtainable in once-through operation. The limiting raw oil throughput may be set by the size of the reactor or fractionator, for certain maximum vapor velocities cannot be exceeded in these vessels. Further it is necessary to supply additional heat to the reactor when recycling in order to maintain a heat balance in the catalyst section. This is usually done by installing a preheater on the feed to the reactor, although some raw oil preheat may be obtained by heat exchange with the fractionating column bottoms.

A unit designed for recycle operation will cost somewhat more than a unit intended to process the same amount of oil in once-through operation at the same conversion; however, the increased liquid recovery obtained by recycling will offset the additional capital expenditure in many cases.

● **Utilities and operating costs.** The utility requirements for the improved unit, of course, depend upon the type of operation, charging stock, and type of equipment used for heat exchange, pumping, and compression. As a basis for discussion, the normal utility requirements were estimated for the catalyst and fractionating sections of a 2000 bbl. per stream day unit processing Mid-Continent gas oil at 60 per cent conversion in once-through operation.

The utilities required to operate this equipment, which is illustrated on Fig. 3, are summarized in Table 2. The total steam required amounts to 4000 lb. per hr., but 5500 lb. per hr. of steam is produced from the column bottoms steam generator, resulting in a net steam pro-

FIG. 3

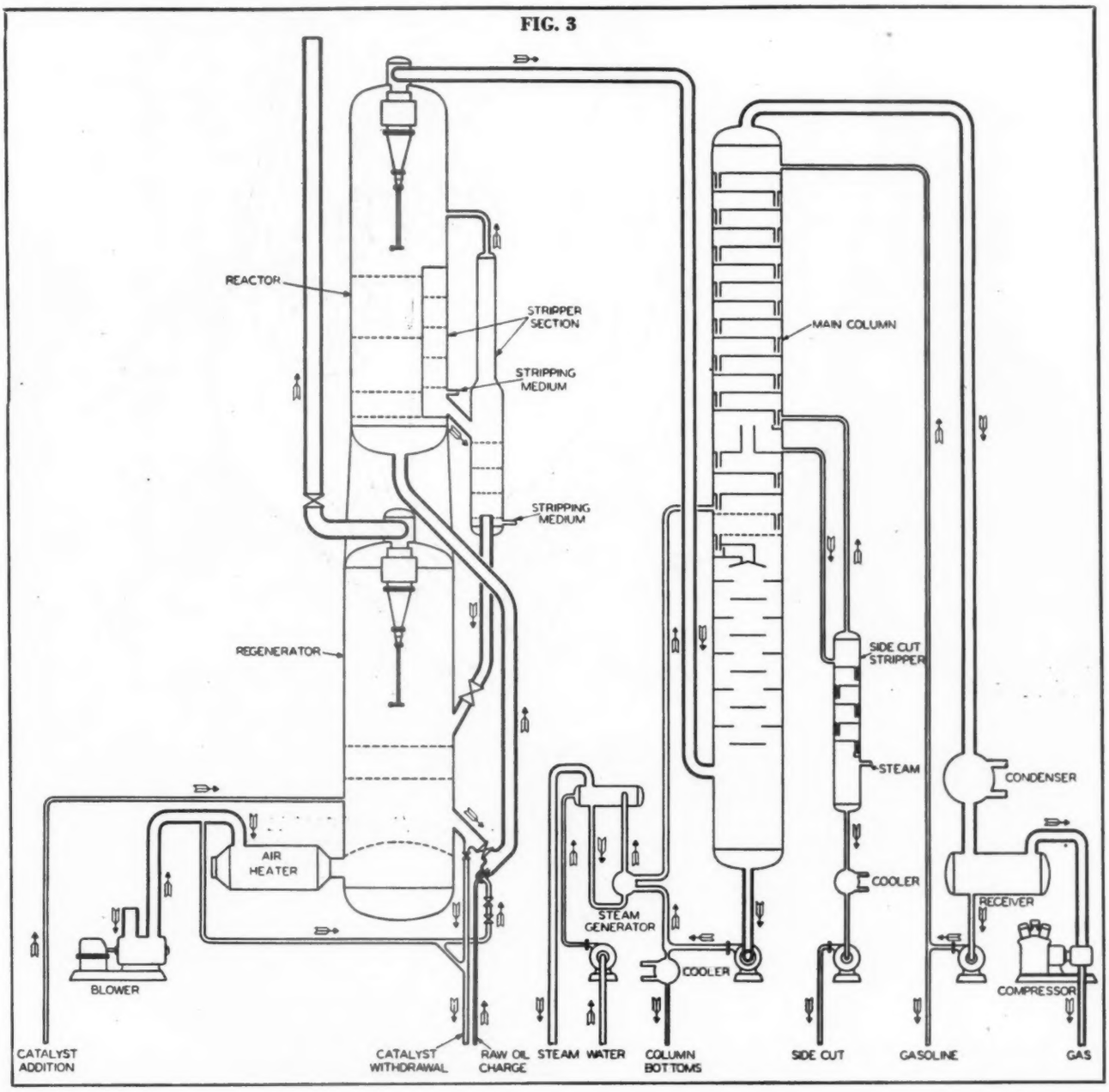


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TABLE 3

Summary of operating costs 2000 bbl. per stream day fluid catalytic cracking unit.

Basis:
60 per cent conversion Mid-Continent gas oil Catalyst section, fractionator, and gas compressors

Item		Dollars per calendar day
1	Operating supervision Foreman at $350 per month	11.70
2	Operating labor 1 operator at $1.50 per hr., 24 hr. 2 helpers at $1.25 per hr., 48 hr.	36.00 60.00
3	Utilities *Steam, 1500 lb. per hr. at 25 cents per M. lb. Fuel gas, 8.0 MM. B.t.u. per hr. at 15 cents per MM. B.t.u. Water, 500 gal. per min. at 1 cent per M. gal. Electricity, 15 kw. at 1 cent per kw.	8.10 25.90 6.50 3.20
4	Catalyst ½ lb. per BCD chg. at 15 cents per lb.	135.00
5	Maintenance (labor and materials)	100.00
6	Laboratory 1 tester, 24 hr. at $1.00 per hr. Chemicals, materials, etc.	24.00 10.00
7	Royalty 1800 bbl. per calendar day at 5 cents per bbl.	90.00
8	Taxes and insurance	35.00
	Total	528.20
	Cost per bbl. of charge (cents)	29.3

*Credit.

duction of 1500 lb. per hr. All pumps shown on this diagram are driven by steam and the air compressor is driven by a gas engine.

The total heat available in the fuel gas produced after polymerization would amount to 31 MM B.t.u. per hr. It is estimated that 3 MM B.t.u. per hr. of fuel gas would be used in driving the gas compressors required to feed the low pressure receiver gas into an absorber operated at 200 lb. per sq. in. An additional 5 MM. B.t.u. per hr. of gas is used for compression of the regenerating air. The net fuel gas available for the boiler house, or heating in other sections of the refinery, thus amounts to 23 MM B.t.u. per hr. The total cooling water for the condenser and coolers amounts to 500 gal. per min. The electricity required for lights and power is estimated at 15 kw.

Using these utilities as a basis, the estimated cost of operating the equipment shown on Fig. 3 is summarized in Table 3. The total cost of operation amounts to 29.3 cents per bbl. of raw oil charge. Credit was taken for the net steam production in these calculations, but no credit was taken for the fuel gas production. With the operation of a stabilizer and absorber to prepare debutanized gasoline and a liquid C_3-C_4 feed to the polymerization unit, the total operating cost would be approximately 33 cents per bbl.

● **Summary.** The stages in the development of the present simplified fluid catalytic cracking unit for the smaller refiner have been briefly discussed. The principal improvements in efficiency and the mechanical simplifications that have been made are listed below.

1. The reactor and regenerator have been combined into a single vessel, which is erected as a self-supporting column in the smaller sized units.
2. When micro-spherical catalyst is used all secondary catalyst recovery equipment, such as the Cottrell precipitator and a slurry settler or slurry circulating system on the processing side, has been eliminated.
3. The efficiency of both the reactor and regenerator has been improved by the use of additional distribution grids in each section.
4. The redesign of the reactor stripper, the installation of an external stripper, and the additional stripping obtained in the countercurrent regenerator results in a marked improvement in stripping efficiency and a reduction of regeneration requirements.

The improved method of controlling the new unit results in uniform catalyst flow and smooth operation. This method of control has been tested in the 2600 bbl. per day commercial unit.

The flexibility of the fluid catalytic cracking process has been demonstrated by commercial units, which have processed stocks ranging from naphthas to topped crude at reactor temperatures of 800-1000°F. Various recycling operations and combinations of catalytic and thermal cracking operations have been investigated in both pilot plant and commercial units.

The reduced investment and operating costs now permit this process to compare favorably with thermal cracking investment and operating costs. ★★★

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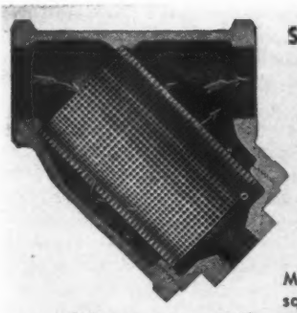

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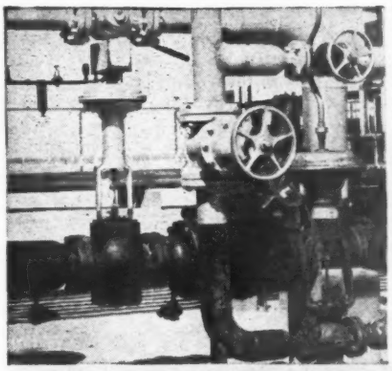
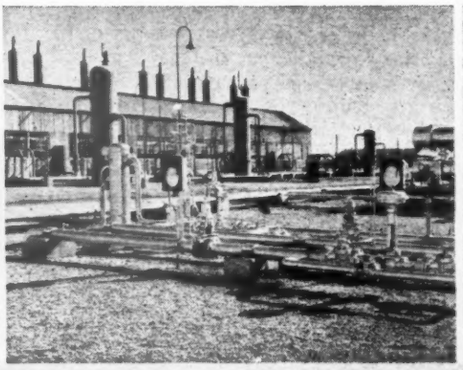
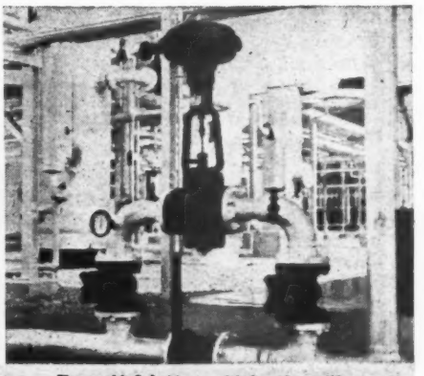


Type H-86 Motor Valves on Refinery vapor lines



Type H-86-D Motor Valves at large cycling plant



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Salt Removal at Ben Franklin Refinery*

By F. DUANE FUQUA

THIS paper has no intention of setting forth a cure-all salt removal method as it is realized that the problems of crude oil desalting are widespread.

The method herein described utilizes well known fundamentals of salt removal. The results are pleasing in that 90 per cent better salt removal is consistently obtained with a chemical cost of less than 2 mills per bbl. of crude processed.

Throughout the discussion the word "salt" refers to the chloride content whatever the positive radical may be.

It is well known that salt is responsible for a great deal of refinery corrosion and deposition in topping, cracking, and exchanger tubes. Chlorides are particularly offensive since by hydrolysis they form hydrochloric acid that reacts with iron to form iron chloride. Hydrogen sulphide present in some oils reacts on the iron chloride forming from sulphide and liberating hydrogen chloride, which again attacks iron and the process is repeated.

Whenever salt-containing oils are evaporated, the salt is precipitated, thus adhering to tube walls and progressively reducing the efficiency of heaters and exchangers both by decreasing heat transfer coefficients as well as substantially increasing pressure drop.

Most salt removal systems are similar in that they are integrated into essentially three main parts.

1. Introduction of water to the crude.
2. Emulsification of water and crude.
3. Demulsification of crude.

The greatest difference between salt removal systems is in the method utilized in carrying out each step.

The process as utilized at the Ben Franklin Refining Company as shown by Fig. 1 involves introduction of a metered quantity of preheated water five pipe diameters from the suction of a reciprocating crude oil charge pump. Water used is from the discharge of the cooling water circulating pump, which takes suction from a hot well that receives the hot effluent from several condenser boxes. Make-up water to the hot well comes from a pond filled by surface water. The water has a relatively low hardness, but often contains a considerable amount of dissolved and suspended solids. The water circulating pump produces sufficient head to put the required amount of processing water through a brine to water exchanger and into the suction of the crude pump; however, should more pressure be desired, a small reciprocating pump has been provided.

An orifice has been installed on the water line and a flow control indicator allows the operator to know at all times how much water is being injected. Valves allow the water line to be blocked from the crude and bypassed to a barrel to permit calibration of the meter at regular intervals as a safeguard against orifice fouling or mechanical trouble within the flow indicator.

Although the water from the hot well is 90-100°F., the temperature of the water is raised to approximately 130°F. by heat exchange with the effluent brine, which is drained to a spare tank until such time as it may be disposed of.

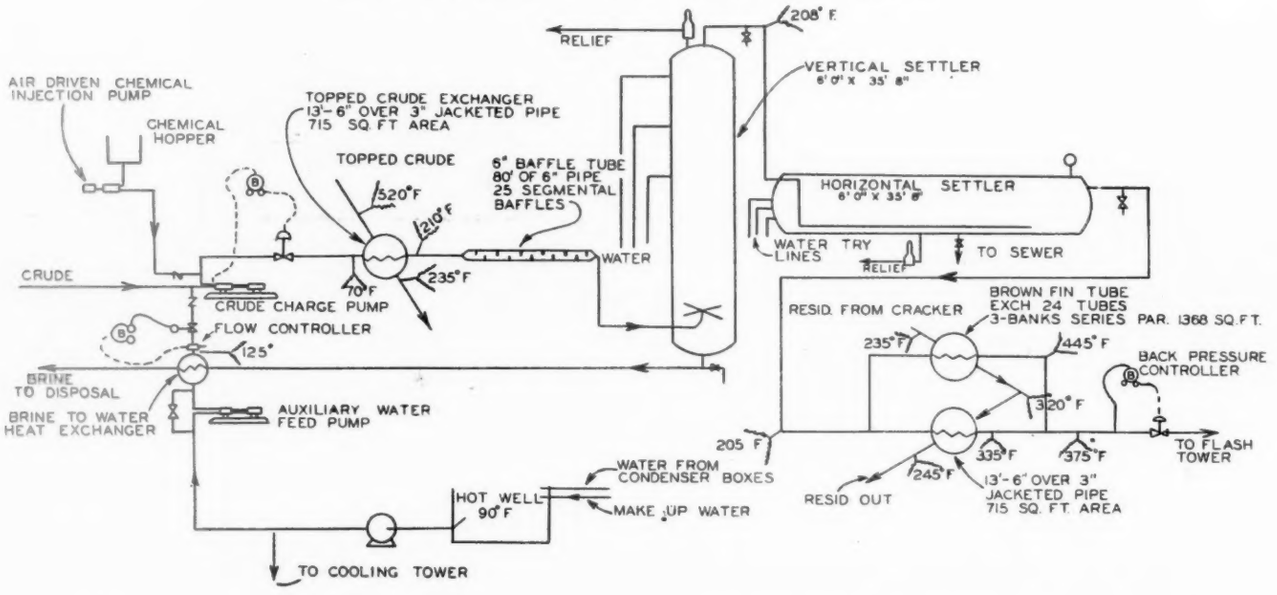
Demulsifying chemical, as required, is pumped by means of an air-driven chemical injection pump into the crude five pipe diameters downstream from the crude pump discharge. Chemical rates are easily adjusted by length of pump strokes, speed of pump, and number of cylinders operated. The quantity of chemical is obtained by direct gauge from small hoppers. Operators are responsible for quantity of chemical used and are at all times cognizant of the amount being used per shift.

Water emulsion is formed by passing the crude and water mixture through an air operated, double port, throttle type back pressure control valve. The valve, with Fisher Wizard controller, is set to hold a given back pressure on the crude pump, thus controlling the amount of pressure drop required for emulsion.

Next the emulsion passes through a topped crude to crude heat exchanger where sufficient heat is picked up to break the viscosity of the crude. Exchangers now being used for this service are 23 60-ft. lengths of 6-in. over 3-in. jacketed standard pipe connected in series. With 751 sq. ft. of external tube surface the mixture of crude and water is heated from 70°F. to approximately 210°F. while the 60-65 per cent yield of topped crude is cooled from 520°F. to

*Presented before Western Petroleum Refiners Association, Fort Worth, Texas, March 25-27, 1946.

FIG. 1. BEN FRANKLIN SALT REMOVAL EQUIPMENT



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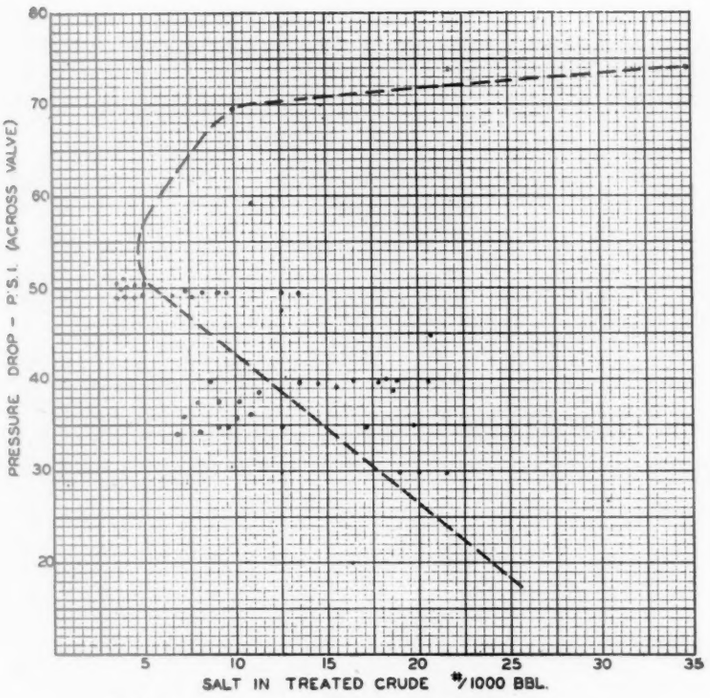

FIG. 2. ΔP vs. SALT IN WASHED CRUDE
(Other conditions varying)

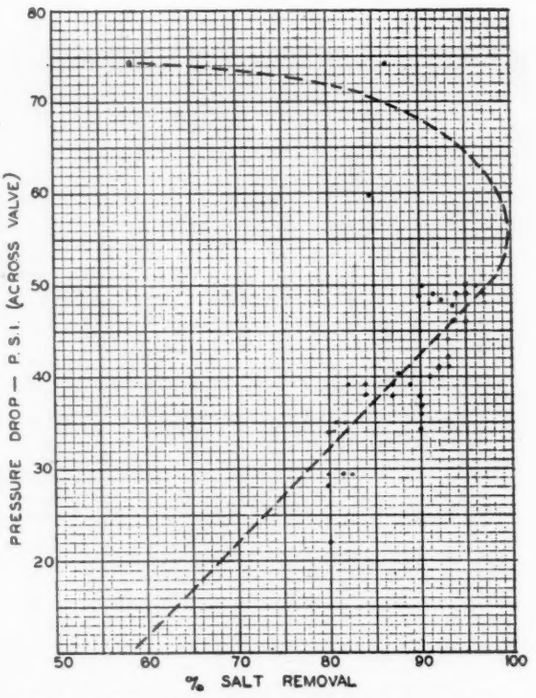

FIG. 3. PER CENT SALT REMOVAL vs. ΔP.
(Other conditions varying)

235°F. Crude is piped through the tube side and topped crude passes through the shell countercurrently.

Crude passes directly from the heat exchangers into a horizontal baffle tube. The baffle is fabricated of 80 ft. of 6-in. pipe with 25 slightly larger than semicircle segmental baffles welded into the pipe at regular intervals. Pressure gauge connections have been installed before and after the baffle, which may also be used for sample connections, or water or chemical insertion points. (They have never been used as such during the course of this investigation.)

From the outlet of the baffle tube, crude enters the bottom head of a 6-ft. by 35-ft. 8-in. vertical settler. The feed nozzle of the vertical ells up into the vertical and terminates in a cross distribution header. The vertical vessel contains a perforated plate with 1-in. holes on 2-in. centers situated directly below the top manway 6 ft. from the top of the vessel. The plate presently has no use, but at one time supported an excelsior packing that at the time proved to be worthless. Try cocks are situated 20 ft., 24½ ft., and 29 ft. from the bottom of the vertical vessel. A level of approximately 20 ft. is maintained in the vertical and crude is scrubbed countercurrently with water breaking from the emulsion.

Hot water is drawn from the vertical settler and exchanges heat with the fresh water charge. The brine drawn off is hand controlled. Water-washed crude passes from the top of the vertical vessel into a 6-ft. by 35-ft. 8-in. horizontal settler where additional settling time is afforded. Actually the horizontal vessel is in the system only as a safety factor.

Crude enters the horizontal vessel through a perforated distribution header that runs longitudinally the full length of the vessel. The header was originally intended to provide additional water scrubbing through a water level held in the horizontal vessel. Crude outlet is on top of the head opposite the feed entry. Try cocks are provided on the horizontal drum, also water may be drawn from the bottom of the vessel to the sewer.

A pressure gauge on the outlet of the horizontal drum serves as an index for the back pressure that is held on the outlet of the far exchanger.

Crude from the horizontal drum is split through two exchangers where heat is picked up from cracking plant residuum. One exchanger is a Brown fin-tube exchanger piped series parallel 24 tubes—3 banks of 8 tubes, with 1368 sq. ft. of external surface, exchanging heat with hot residuum (735-520°F.) directly from the cracking plant. The other exchanger is identical in construction with the topped crude to crude exchanger, i.e., thirteen 60-ft. lengths of 6-in. over 3-in. jacketed pipe with crude on the tube side and residuum effluent from the Brown exchanger on the shell side (520-245°F.).

Under normal plant operation 375°F. crude preheat is obtained up to this point.

A 2-in. Fisher Wizard back-pressure control is placed on the effluent of the exchangers. Enough back pressure is held at this point to prevent vaporization within the exchangers and to maintain a back pressure on the horizontal settler of 125 to 140 lb.

Crude then passes to a flash tower where approximately 10 per cent of the crude is flashed to the fractionators and the tower bottoms are charged to the furnace.

In order to effect the greatest salt removal it is necessary that the salt be given every opportunity to contact water. Thus it was believed that water wash in addition to the original emulsification would be beneficial; however, any number of water washes is of no benefit if the film of the emulsifying agent is not broken, for this film encases dispersed droplets of brine.

The smaller the droplets the "tighter" the emulsion and the more difficult it is to break. So far as possible, the emulsion must be made to fit the crude; conversely, the demulsification process must fit the emulsion.

If small droplets of water are to be coalesced it is necessary that the surface tension of their binding sheath be reduced to such a point that the water droplets may break out by gravity.

As surface tension is in direct relationship to viscosity, it is obvious that to effect good salt removal the viscosity of the crude must be lowered to such a point that droplets of water are no longer restrained by their binders. In the case of water and crude, if the viscosity is reduced by temperature, a greater difference in specific gravity will exist between the oil and brine, thus allowing a quicker and better separation.

If droplets of water can be made to contact each other thus forming larger droplets, gravitational separation is greatly accelerated. Turbulent flow is conducive to desired contact. Furthermore, the presence of baffles, grit, and chat make for greater contact. Often, if

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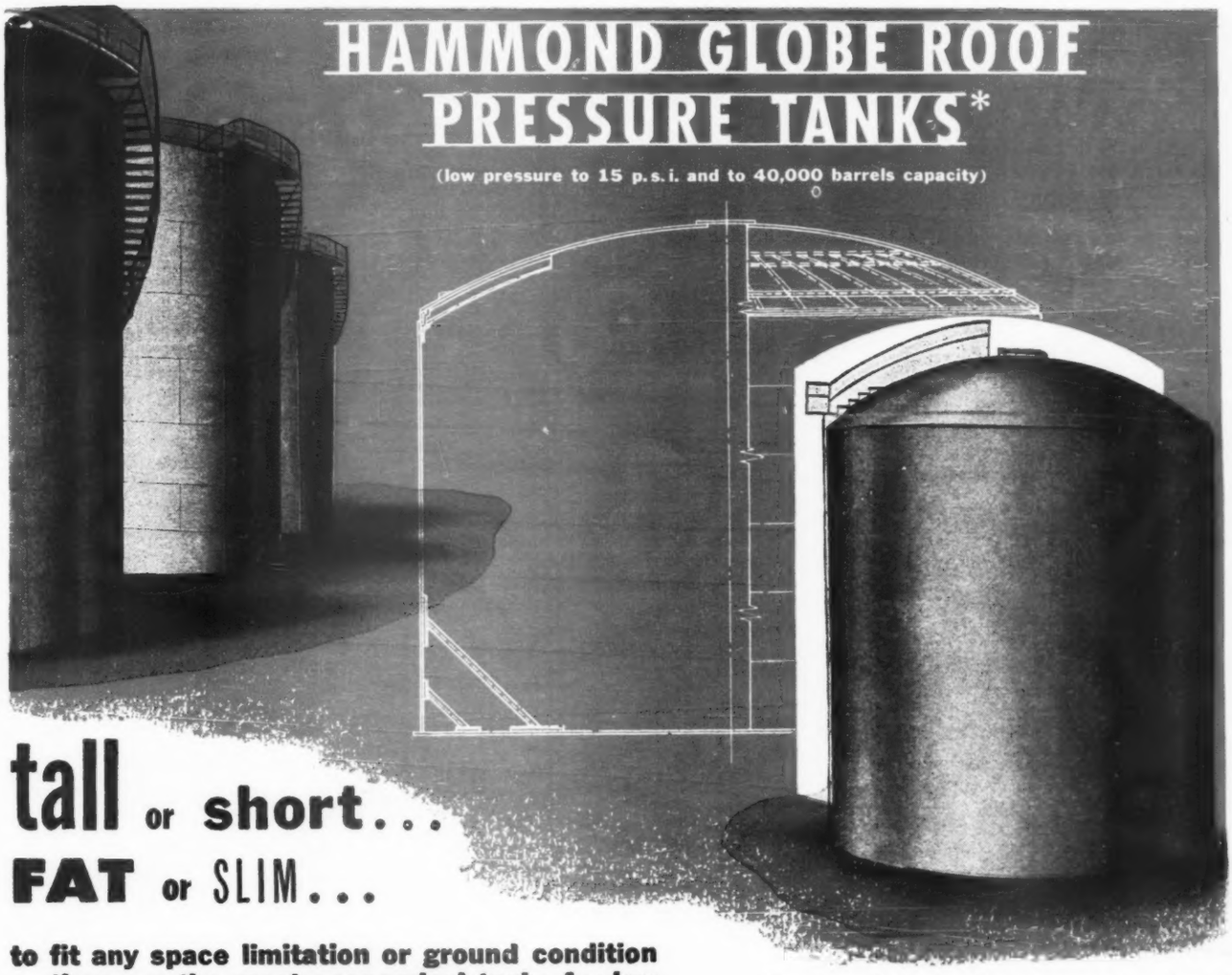

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[1]Comparative records of losses of the same product stored in this tank and in other containers of conventional types operating at much lower pressures, indicated that savings during three months of summer storage more than paid for the additional cost of this container over one of the cone-roof type having the same storage capacity.

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emulsions are difficult to break, small quantities of demulsifying chemicals may be used as required.

Salt removal at Ben Franklin Refinery is subject to several variables, some of which are extremely important whereas others seem to be of little consequence. In every case, however, it is deemed advisable that all variables be watched, recorded, and correlated. It is important that the operators be educated to the variables and be kept abreast of all significant correlations.

● **Pressure drop.** Pressure drop is probably the most critical of all variables. A back-pressure control valve on the discharge of the crude charge pump allows a constant pressure drop to be maintained. Previous to the installation of the control valve, a gate valve on the discharge of the crude pump was kept in a throttled position to maintain the necessary back pressure. Various pressure drops have been tried on our composite crude ranging from 0 to 100 lb. With minimum pressure drop salt removal is poor, ranging from 60 to 80 per cent removal. Forty to 50 lb. differential across the emulsifying valve seems to be ideal for our crude. Pressure drop in the region of 75 to 100 lb. will often cause too tight an emulsion, which, although often accompanied by excellent salt removal, is just as often subject to rather high water carryover (1 per cent and greater).

Once the optimum pressure drop is found, small variations do not seem critical as can be readily evidenced by the fact that Ben Franklin uses a reciprocating charge pump rather than a centrifugal pump.

Pressure drop vs. salt content of final crude, with other conditions unchanged, showed a very good correlation in the region of 0-60-lb. pressure differential.

Pressure drop vs. salt content of final crude (Fig. 2) and pressure drop vs. per cent salt removal (Fig. 3) with other conditions varying, were correlatable.

Table 1 shows normal pressure measurements taken progressively through the salt removal equipment.

The back pressure held on the system appears to be sufficiently high to prevent vaporization from occurring.

In order to get a feel of the pressures required, a small bomb was prepared and equipped with thermometer well and pressure gage connection. The bomb was charged with a composite crude containing approximately 10 per cent water in emulsion. The mixture was heated to 280°F. and pressures and temperatures were recorded as the sample cooled. At 270°F. the apparent vapor pressure of the sample was 50 lb. (Fig. 5.)

● **Temperature and viscosity.** Temperature, as previously discussed, must be high enough to reduce the surface tension of the oil to the point that water will break out. Assuming that surface tension is a direct function of viscosities, temperature viscosity curves of each of

TABLE 1

	Pressure lb. per sq. in. ga.
Crude pump	210
Exchanger inlet	159
Baffle inlet	150
Baffle outlet	145
Vertical settler inlet	143
Horizontal settler outlet	140
Pressure outlet of residuum to crude exchangers	133

FIG. 4. Temperature vs. viscosity curves of Ben Franklin crudes

	Grav.—°API		Grav.—°API
1—Healdton	30.0	4—Woodbine	26.3
2—Aylesworth	37.4	5—Aylesworth-Mead	38.1
3—Aylesworth	36.5	6—Snap-Tank Sample	
		7—Snap-Tank Sample	35.8

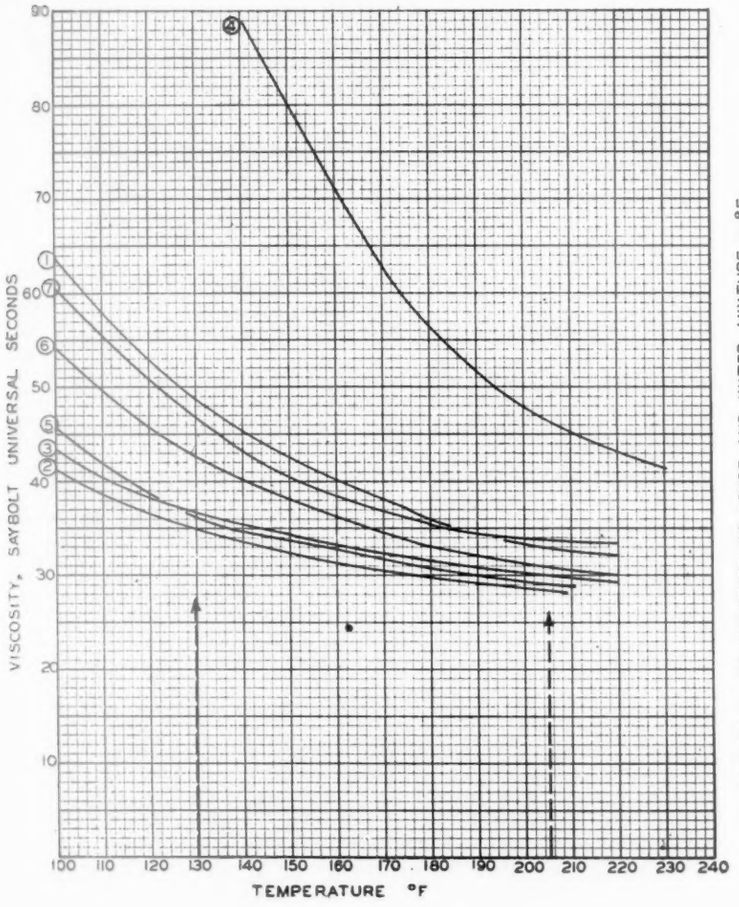
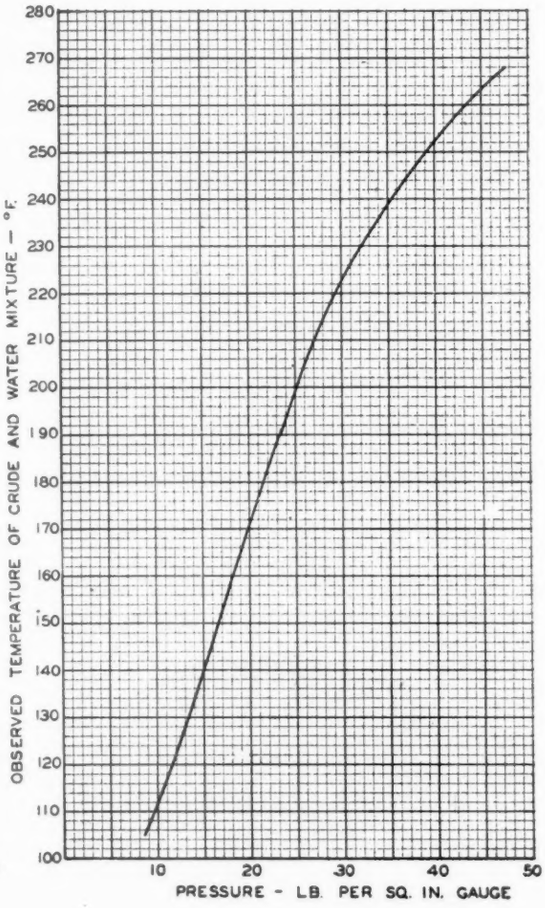


FIG. 5. Apparent vapor pressure of a composite crude sample plus 10 per cent H_2O.



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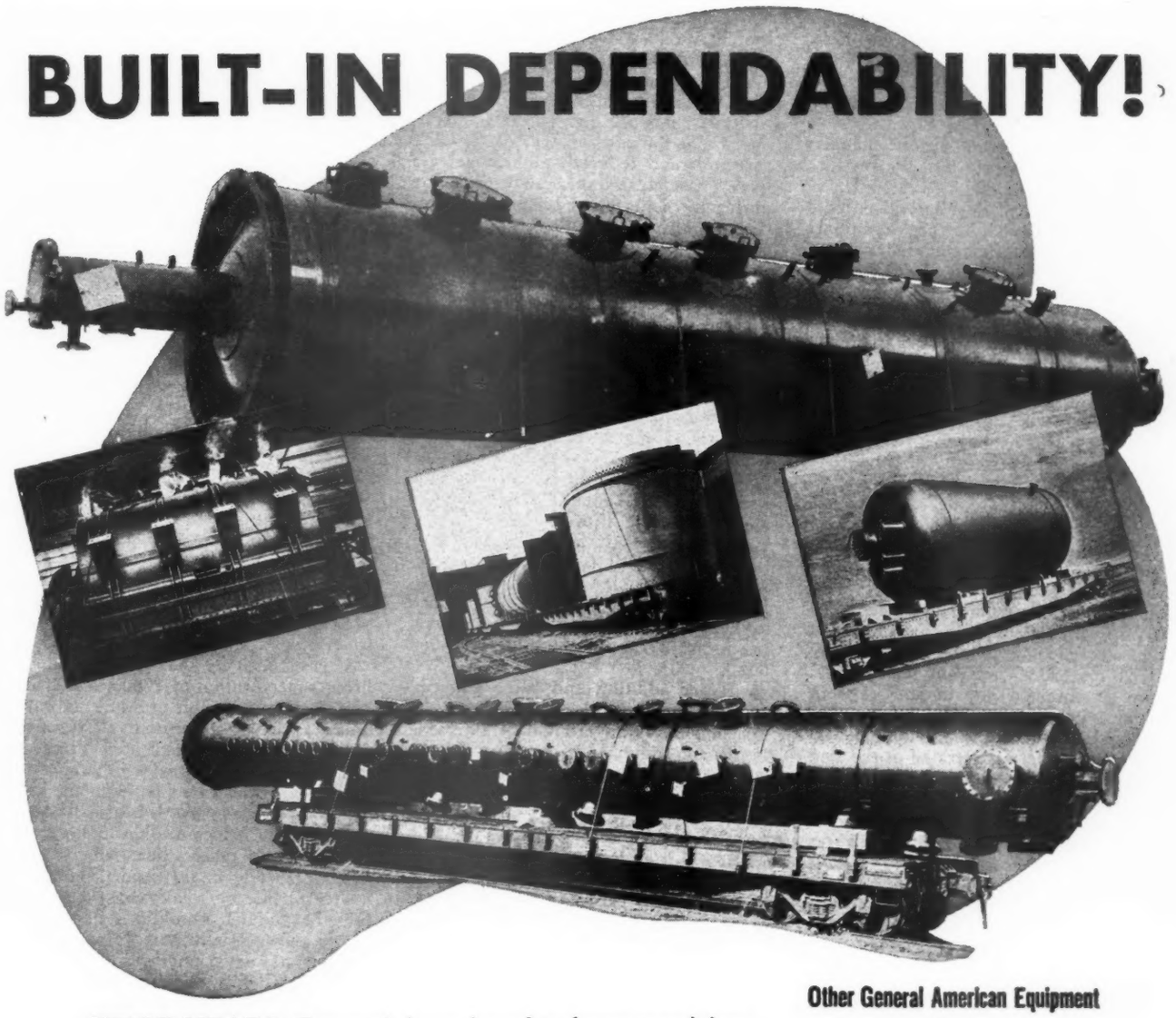

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our crudes have been plotted and projected. (Fig. 4.) It appears from these data that a viscosity, Saybolt Universal Seconds, of approximately 40 sec. or less on our crudes must be reached to obtain optimum salt removal.

Previous to a recent heat exchanger revamp, the temperature of the vertical settler was approximately 130°F. These conditions afforded salt removal only in the order of 50 to 80 per cent depending upon the type of crude charged and the amount of salt in the crude, i.e., with these conditions, the greater amount of salt in the crude charge, the better the per cent salt removal. Considerable amount of chemical was also used in an attempt to effect an emulsion break. The viscosity of our crude at 130°F. was 50 SUS and above.

Following the heat exchanger revamp, the temperature of the vertical settler varies between 190 and 220°F. depending upon the quantity and temperature of topped crude exchanging heat with the crude.

At 220°F. and with an average crude charge, the SUS viscosity is 34 sec. With the aforementioned pressure drop of 40 to 50 lb. water flow of 5 to 15 L.V. per cent of crude charge, and SUS viscosity of 34 sec., 90-95 per cent salt removal may be obtained day in and day out without any chemical addition.

The importance of maintaining low viscosity has been illustrated at the Ben Franklin Refinery by operating at the above conditions and suddenly changing the charge stock to a 26.3 API gravity Woodbine crude, which with approximately the same temperature in the vertical settler increases the effective viscosity to 50 sec. SUS. The effect is as one would forecast, an increased water carryover and reduced salt removal. If, however, demulsifying chemical is added during the charging of the heavy crude, substantially good salt removal is still obtained. For this reason Ben Franklin Refinery uses a small quantity of chemical as a safeguard against slugs of heavy crude or tank bottoms. It is planned to provide a system whereby segregated crude stocks cannot be charged directly to the stills, but must be blended with the composite crudes.

Temperatures required for the vertical settler should be in the range of 200 to 250°F. There seems to be no virtual gain in exceeding 250°F., for viscosity curves for Ben Franklin crude tend to flatten out in the range.

At present vertical settler temperatures, no difficulty has been experienced with oil entrainment in the effluent brine; however, before the recent heat exchanger revamp some oil entrainment in the brine was intermittently encountered.

● **Water addition and brine concentration.** The quantity of water required for emulsifying the crude does not seem to be too critical. It appears that a minimum of 5 per cent volume of fresh water injection should be used, but no maximum has been found other than limitations that might be found in added heat transfer duty due to the presence of additional water. As high as 15 per cent fresh water charge has been used; however, it must be pointed out that in a water-wash system such as the one outlined, a water level must be maintained. As the salt concentration of the water level for a given water flow rate will vary with the salt concentration of the crude, it becomes rather important to check the water-wash salt concentration and control the quantity of water charged accordingly.

It has been found at Ben Franklin Refinery that a concentration of 500 to 1000 lb. NaCL per 1000 bbl. of water is ideal, not particularly from a washing efficiency standpoint but as a safety factor, for a loss of temperature, exceedingly high pressure drop across the emulsification valve, or some unforeseen factor might cause a carryover of a quantity of this concentrated salt water. If one disregards safety factors, however, it is known from our data that water salt concentrations on the order of 1500 to 2500 lb. per 1000 bbl. of water give a satisfactory water wash.

It is claimed by some refiners that a brine concentration of 2000 to 4000 lb. of salt per 1000 bbl. of water is optimum. To expect improved salt removal from the more concentrated brine is quite logical, for a greater difference in specific gravities exists between the salt solution and the crude. It is also claimed that stronger brines contain higher concentrations of those demulsifiers that occur naturally in the crude. However, no reasonable correlation could be obtained at the Ben Franklin Refinery that would show the advantage of one brine concentration over another.

Obviously, with refineries where water is expensive enough to become a definite factor, salt concentration should be regulated for minimum water consumption.

The quality of the water used by the Ben Franklin Refinery might be questionable to some. The source of water

FIG. 6. ASTM DISTILLATIONS OF VARIOUS BEN FRANKLIN CRUDE CHARGES

	Gravity	Average Salt
Top line—Aylesworth-Mead	38.1	50 lb. per 1000 bbl.
Center—71 Tank Crude	35.8	104 lb. per 1000 bbl.
Bottom—Woodbine Crude	26.3	217 lb. per 1000 bbl.

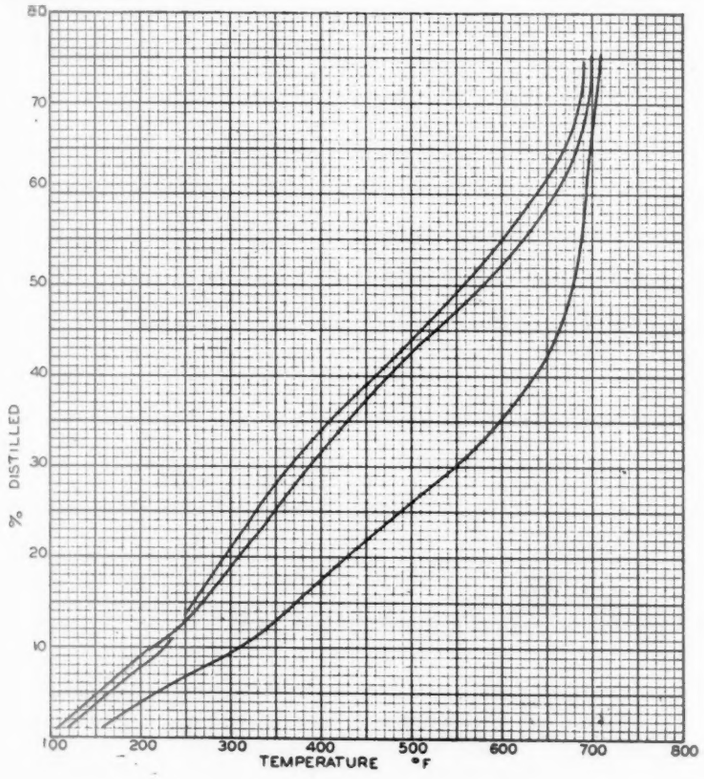

TABLE 2

Analysis of H_2O from hot well

pH = 8.0

Total hardness =	5.0 grains per gal.
Chlorides =	4.2 grains per gal.
P =	0.0 grains per gal.
M =	7.0 grains per gal.
Suspended solids =	0.4 grains per gal.
Dissolved solids =	14.1 grains per gal.
Total solids =	14.5 grains per gal.

TABLE 3

Analysis of water from vertical settler.

Lb. per 1000 bbl.	H_2O	Weight, per cent
$CaCl_2$	192	19.5
$MgCl_2$	162	16.4
NaCl	634	64.1
	988	100.0

pH = 7.9

7.6 grains per gal. suspended solids.

590 grains per gal. dissolved solids.

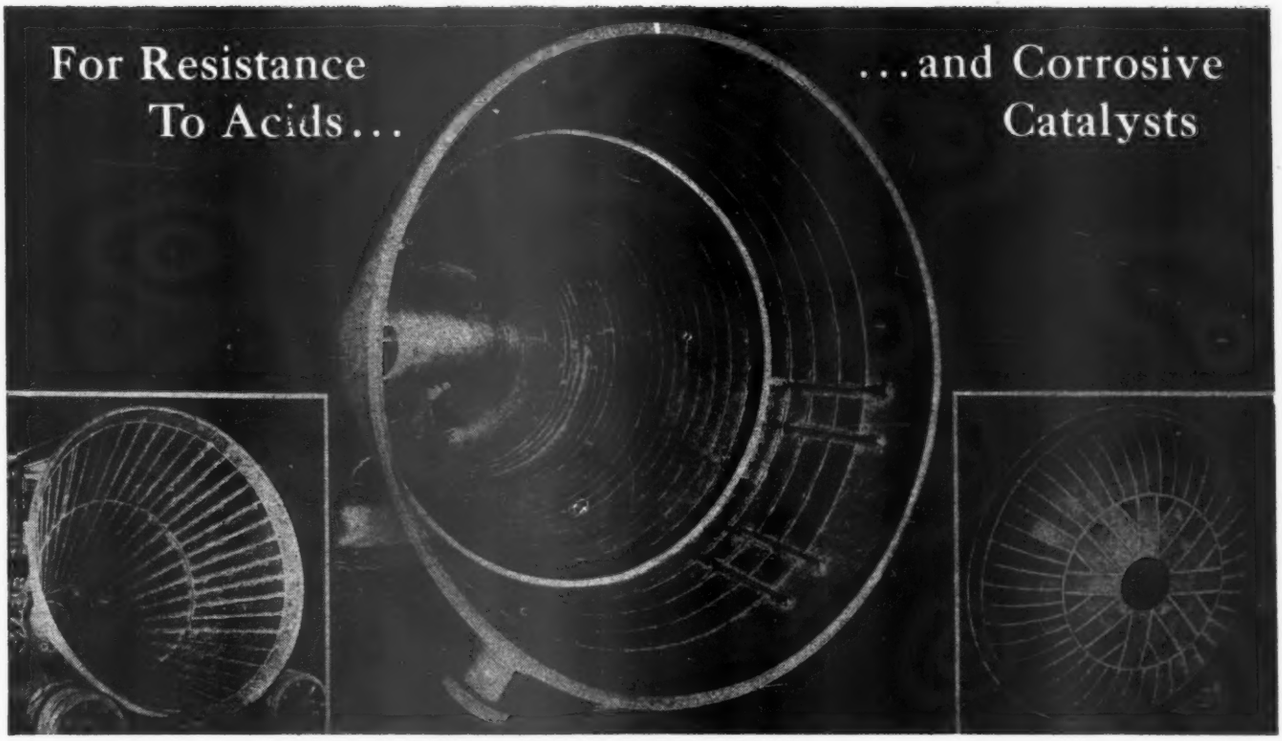

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TABLE 4—Basis 3000 bbl. per day crude charge rate.

	No. 1 valve	No. 2 valve	No. 3 valve	Between settler	Out of horizontal settler
	100 per cent water	26 per cent	3 per cent		0.3 per cent
	100 per cent water	6.5 per cent	4.8 per cent	0.2 per cent	0.2 per cent
	100 per cent water	100 per cent water	8.0 per cent	0.3 per cent	0.2 per cent
	100 per cent water	8.0 per cent	3.0 per cent	0.2 per cent	0.2 per cent
Settling time above the water level at 3000 bbl. per day Charge, min.	0	11	22	36	117

TABLE 5

Requirement	Temperature, °F.	Residence time, min.	Velocity, ft. per sec.
Pump to Tc each	70		
Exchangers	70–210	3.17	4.2
Baffles	210	1.08	1.24
Vertical settler	210	35.5	0.0074*
Horizontal settler	208	81.0	0.0074

*Assumed 20 ft. water level.

is a hot well, which at times has a rather high dissolved and suspended solids concentration. (Table 2 and Table 3.)

Although the conditions of the water might be suspected as slightly erosive or corrosive it has not shown any apparent ill effects. Should any corrosion be found in the vertical vessel at any time in the future, it is planned to install a ¾-in. ganister liner (luminite cement and ground brick ganister).

No trouble has been experienced with fouled heat exchangers as heat transfer coefficients have remained approximately the same throughout the run. Apparently all solids are discarded with the water drawn from the vertical settler. A definite advantage, however, is assumed in the contact coalescing value of suspended solids when present in the emulsions.

● **Solids at water oil interface.** Accumulation of solids at water oil interface that might stabilize water oil emulsion has not been encountered; however, the try lines are so situated that periodic skimming of the interface would be possible if necessary.

● **Chemical addition.** Chemical used at the Ben Franklin Refinery is Visco No. RM 64. As previously pointed out, it is doubtful whether the chemical is needed 95 per cent of the time, but it is good insurance against slugs of heavy crude or tank bottoms.

The amount of chemical currently used is approximately 1 qt. per 500 bbl. of crude charge, which represents a cost of 1.0 mill per bbl. of crude.

● **Settling time.** It has often been asked among refiners and designers as to how much settling time is actually required for salt removal equipment. Some simple tests carried out on the Ben Franklin salt removal system may throw further light on the subject.

As a 20-ft. water level is maintained at the bottom try cock of the vertical vessel, samples of crude are available at each of the remaining two try cock levels, between the horizontal and the vertical settlers, and the outlet of the horizontal. BS&W is occasionally checked at each of these points to determine how quickly the emulsion break is taking place. Table 4 shows the "break" obtained during normal operations.

From these data it appears that little settling time is required when a good break is experienced, but for cases of water carryover due to tight emulsion, the advantage of additional settling time seems doubtful. This fact was further substantiated during periods of high water carryover occurring previous to the heat exchanger revamp as little emulsion break was encountered beyond the vertical settler. The final settler is insurance against faulty operation, i.e., high water levels, etc., and probably has a significant value.

Residence time and velocities throughout the salt settling equipment at 3000 bbl. per day crude charge are shown by Table 5.

● **Contact and coalescing.** The baffle section is intended to create a turbulent flow and a contact surface to coalesce so far as possible the droplets of water before they reach the vertical settler. Also, if any salt still remains coated with a paraffin sheath, the additional contact in this hot section tends to break down final resistance before entering the vertical settler.

If the baffle had not been satisfactory, it was planned to use a grit or chat as a coalescing medium in the lower section of the vertical vessel.

An ostensible need for the additional contact section was indicated by a microscopic study of raw and washed crude made previous to the addition of the baffle section.

The raw crude showed three different types of crystals: One with definite angular plane surfaces, another in the form of small threads, and a third type that appeared as a black shapeless mass. Crystals with angular plane surfaces were of various sizes and represented approximately 75 per cent of the total crystalized material. The thread type material constituted approximately 20 per cent of the total, and the remaining 5 per cent was the black masses of shapeless substances.

Examination of crystals in the washed crude showed only the smallest of the

TABLE 6—Typical operating data (December-January operation)

Temp. vertical settler	Pressure drop	Water LV per cent of crude	Water LV per cent carryover	Brine concentration lb. NaCl per 1000 bbl.	Crude charge, bbl. per day	Salt in lb. Nacl per 1000 bbl.	Salt out lb. Nacl per 1000 bbl.	Per cent removal	Chemical used, qt. per day	Chemical cost per bbl. crude, cents per bbl.
210	40	5.0	0.4	..	2885	88	9	90	2	0.037
200	35	7.0	0.2	570	2534	65	10	85	13	0.275
200	35	8.5	0.2	1500	2550	125	13	89	6	0.126
200	35	8.5	0.2	..	2548	121	7	95	12	0.253
200	35	11.2	0.1	..	2526	120	7	94	12	0.256
210	50	11.2	0.7	908	2441	124	6	95	10	0.221
190	50	10.0	0.2	..	2445	109	13	88	9	0.198
195	50	10.0	0.4	796	2754	121	9	93	6	0.117
195	40	10.0	0.4	..	2721	124	14	89	9	0.178
200	45	12.0	0.4	936	2730	180	13	93	11	0.216
185	40	7.0	0.4	584	2177	101	13	87	8	0.198
200	35	6.2	0.2	..	2500	77	10	87	8	0.172
210	35	8.0	0.1	..	2821	105	10	90	8	0.153
195	35	6.0	0.2	..	2232	120	9	93	0	0
210	35	6.0	0.2	..	3053	115	11	94	8	0.140
200	40	6.0	0.2	..	3132	163	15	91	10	0.171
200	45	6.0	0.2	..	3100	135	11	91	10	0.176
220	50	9.0	0.2	..	3089	117	11	91	11	0.190
200	80	9.0	0.3	1563	1983	85	10	88	3	0.081
200	80*	7.0	0.8	..	3601	85	35*	59*	2	0.036
210	75	6.0	0.4	1560	2500	85	10	88	2	0.043
210	10–15†	12.0	0.2	1572	2500	87	35†	60†	2	0.043
205	50	13.0	0.2	..	2226	80	6	93	8	0.193
210	50	12.0	0.2	1160	2000	60	6	90	9	0.255
215	20‡	10.0	0.1	2236	2000	88	18‡	80‡	8	0.215
205	40	12.0	0.2	2092	3273	253	26	90	6	0.098
200	40	12.0	0.2	724	3200	69	5	93	6	0.101
205	45	12.0	0.2	700	2809	81	4	95	6	0.114
210	45	13.0	0.2	700	2758	80	2	98	6	0.117
200	50	12.0	0.2	400	3014	85	3	96	6	0.107
205	50	13.0	0.1	420	3014	80	2	98	6	0.107
200	50	13.0	0.2	444	2586	87	7	92	5	0.104
210	50	12.0	0.1	..	2739	60	2	97	6	0.118
205	50	13.0	0.1	..	2700	55	2	97	5	0.100
200	50	13.0	0.1	564	2564	50	2	96	5	0.105
205	50	12.0	0.2	450	2174	65	3	95	5	0.124
250	50	12.0	0.1	500	1977	48	3	94	5	0.126
205	50	11.0	0.2	460	1900	76	2	97	5	0.136

*Pressure drop too high, poor emulsion break. †Pressure drop to low; failure of back pressure valve.
‡Pressure drop too low.

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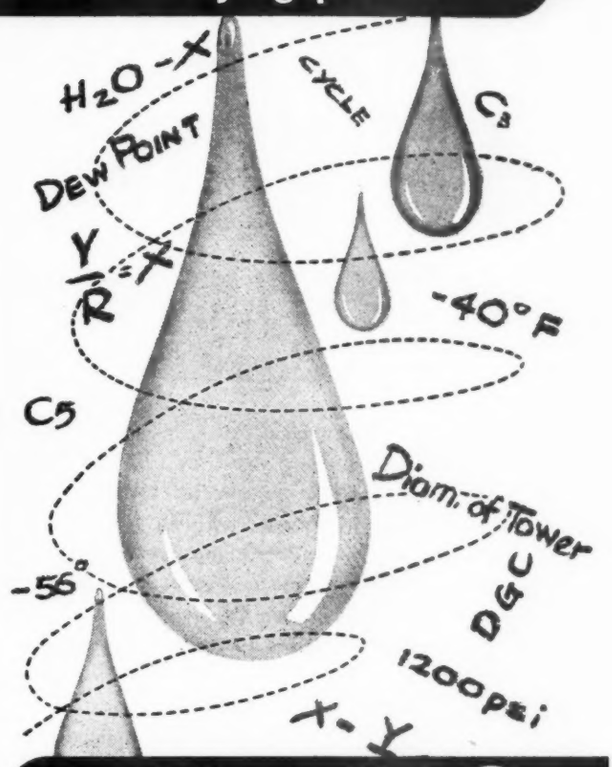

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angular plane crystals remaining plus all crystals of the other types.

Crystals of the second and third class were not positively identified as salt crystals, for they may have been a form of basic sediment, but it was reasonably concluded that the remaining minute angular crystals were salt.

From these data it seemed that further contact of water with the crystals was necessary after the wax film had been broken with heat.

Obviously the baffle has been beneficial in this capacity since at no time previous to its installation could the salt content of the crude be consistently reduced to as low levels as is currently being accomplished. Other factors were probably equally important, however.

A representative month's crude run is shown in Table 7.

TABLE 7

Gravity, API	Crude	LV per cent
30	Healdton	28
32	Oscar	
41	Joliff	7
36	Aylesworth	30
36	Mead	7
26	Woodbine	28

Average gravity of month's charge equals 32.0 API.

ASTM distillations of various Ben Franklin crude charges are shown by Fig. 6.

UOP K (characterization factor) estimated from gravity-viscosity correlations vary from 11.9 to 12.2 for various Ben Franklin crude charges. This indicated crudes that are predominantly paraffinic in nature.

A composite crude evaluated by Bureau of Mines method also showed the crude to be paraffinic.

Typical operating data are shown by Table 6.

From the data and observations made of operation of Ben Franklin crude charges, the following points should be emphasized.

Best emulsification is obtained with 40 to 50-lb. pressure drop across emulsifying valve.

Temperature within the vertical settler must be maintained for desired emulsion-breaking viscosities (200-220°F.)

Pressure should be sufficient to prevent vaporization (130-150 lb. per sq. in. ga.)

Additional contact of water and crude should be induced after the crude viscosity has been reduced.

Water should be metered adequately to maintain a constant fresh water charge for a reasonable brine concentration within the vertical settler. (5-15 LV per cent of crude charge.)

If chemical is used, adequate control and correlation should be employed to minimize expenditure and obtain optimum results.

Operators must be made a part of this salt removal program by making all correlations available to them and emphasizing the montetary value of a salt free product. ★★★

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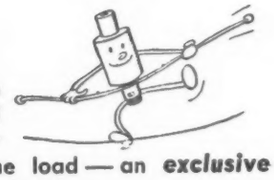

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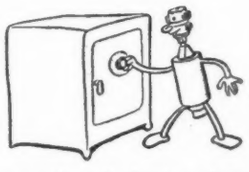

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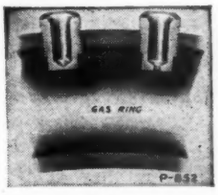

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Interstate Natural Gas Transmission Lines*

By **N. C. McGOWEN,** *President,* United Gas Pipe Line Company

HISTORICALLY[1], Texas has imported substantial and economically significant quantities of natural gas since 1907, when the first natural gas pipe line was laid across Texas' state line. Beginning with that year I will recount the history of Texas' interstate natural gas pipe lines. In that connection a map is annexed hereto, as Appendix "A", showing Texas' interstate gas pipe lines. It shows their sources of supply, their routes and markets in Texas, and indicates their export markets.

The first of Texas' interstate gas pipe lines was built from the Caddo field in northwest Louisiana to Texarkana in the year 1907. Two years later, in 1909, a second line brought gas into the State of Texas from the Caddo field to supply Marshall, Atlanta, and Queen City, Texas.

At that time the Caddo field in northwest Louisiana was an important gas reserve and was connected to Shreveport and other nearby Louisiana towns as early as 1906.

There were no other natural gas pipe lines constructed across the Texas state line until 1917 when the Lone Star Gas Company began the construction of a 12-in. line from the Gas City field in southern Oklahoma to supplement the declining supply of gas for their system from the Petrolia field at Petrolia, Texas, which was connected by a 16-in. line to the cities of Fort Worth and Dallas and a score of other towns in North Texas. Several years later the Lone Star Gas Company constructed a 16-in. line from the Fox Central field in southern Oklahoma to further supplement the supplies of their North Texas system.

The first large long-distance interstate natural gas pipe line was also constructed to bring gas into the State of Texas. It was an 18-in., 16-in., 14-in. line (now part of the United Gas System) built in 1924 by Magnolia Gas Company to transport gas being produced by the Magnolia Petroleum Company in Webster Parish, Louisiana, to the Magnolia Refinery in Beaumont, Texas. Supplemental supplies of gas were obtained from the Waskom and Bethany fields in Texas.

In 1927 the Magnolia Gas Company extended its system in Texas from Waskom to Dallas and Fort Worth to supply the Magnolia Refinery in Fort Worth, the steam electric power plants at Fort Worth and Dallas, and other industries in the vicinity of those cities. This was an 18-in., 16-in., 14-in. line. In 1928 that system's pipe lines were further extended with an 18-in. and 20-in. line from Webster to the Monroe and Richland fields in Louisiana to meet the growing demands for natural gas in Texas.

In 1927 a line (now part of the United Gas System) was built by Dixie Gulf Gas Company to provide additional supplies for Texas markets — 16-in. from Mooringsport, Louisiana to Waskom, Texas, and 22-in. from the Waskom and Bethany gas fields in East Texas to Goodrich, Texas, with an 18-in. extension to Houston, which was inadequately supplied with gas from Southwest Texas. A 16-in. line was constructed from Goodrich to serve the cities of Beaumont and Port Arthur, Texas, and augment the supply to the surrounding territory.

In 1929 Arkansas-Louisiana Gas Company constructed an 8-in. line from its system in Caddo Parish, Louisiana, to Gilmer, Jefferson, Avinger, Hughes Springs, Linden, Mount Pleasant, Mount Vernon, Naples, Omaha, Pittsburgh, Daingerfield, and Winnsborough, Texas, bringing natural gas service into this part of Texas for the first time. This system has since been extended to Talco, and Winnfield. The line built to Texarkana in 1907 was extended to New Boston, Texas, in 1942.

In 1929 the El Paso Natural Gas Company constructed a 16-in. transmission line from fields in southeast New Mexico to El Paso, Texas. In 1931 that line was extended to Phoenix and other communities in Arizona, with an extension to the Republic of Mexico.

In 1930 a predecessor of United Gas Pipe Line Company constructed a 12-in. pipe line from Jenning's field in the vicinity of Laredo, Texas, to Monterrey, Mexico, to supply industrial and residential customers in that city.

Although the Panhandle field was discovered in 1918, and was soon determined to be a major gas reserve, more than nine years elapsed before any sizable pipe lines were constructed to take gas from that field other than to supply the markets in towns and cities nearby. In that year the Cities Service Gas Company constructed a gathering system and gasoline plant in the Panhandle field and 250 miles of 20-in. pipe line between the Panhandle field and its pipe line system in Kansas, making connection therewith at Wichita, Kansas. It further reinforced that system with a 130-mile 20-in. extension to Ottawa, Kansas, and a 39-mile 16-in. extension from Ottawa to Kansas City. It is significant that the first large line to be built therefrom was constructed to take gas to an area that had used natural gas since 1884, but had had no large long-term supply of gas, and, therefore, had suffered many shortages of gas in the intervening years.

In 1928 the Canadian River Gas Company began construction of the second large line out of the Panhandle field. It is a 22-in. line, supplying the 22-in. pipe line of the Colorado Interstate Gas Company, which transports gas to Pueblo, Colorado Springs, Denver, and Cheyenne, and the Colorado Fuel and Iron Company's steel mill in Pueblo; it also supplies smaller communities and industries in New Mexico, Colorado, and Wyoming.

In the fall of 1928 construction was begun on what is now the Consolidated Gas Utilities Corporation's 14-in. pipe line out of the West Panhandle field to augment the gas supply from local fields to 30 communities in Oklahoma and 13 communities in Kansas.

The next line to be built out of the Panhandle field was the Panhandle Eastern Pipe Line Company's pipe line to Indiana. Construction was begun in 1930 on the gathering system in the Panhandle field, and a 22-in. transmission line across Oklahoma and into Kansas, where another gathering system was built in the Hugoton, Kansas, field and connected to the transmission line which originally carried the gas from those two fields through Kansas, Missouri, and Illinois, to Rockville, Indiana, where it connected with, and supplied the Ohio Fuel Gas Company, a part of the Columbia System. Those systems supplied an area that had had natural gas for a long time.

In 1930 and 1931 Texoma Natural Gas Company constructed a gathering system, gasoline plant, and a line 24-in. in diameter from the West Panhandle field to supply the Natural Gas Pipeline Company of America, which also constructed and put into operation its 24-in. line to Chicago. Texoma also constructed a gathering system and gasoline plant in the Panhandle field and a field compressor station.

The Northern Natural Gas Company also constructed and began the operation of its 24-in. line from the Panhandle field to Omaha, Nebraska, and Minneapolis, Minnesota, in 1931.

Other smaller interstate pipe lines were also constructed from the Panhandle field to nearby communities in Oklahoma, Kansas, Colorado, New Mexico and back into Texas between 1927 and 1932.

In 1932 an interstate pipe line was constructed by United Gas Public Service Company, connecting to its transmission line constructed in 1924 by Magnolia Gas Company from Webster, Louisiana, to Beaumont, Texas, to sup-

*Presented at Federal Power Commission hearing, Houston, Texas, January 28, 1946.

1. Historical data from Bureau of Mines "Minerals Year Book" and from correspondence with interstate natural gas pipe line companies operating in Texas.

Mr. Executive Check (√) 'Em

(Above) Two 500 hp main line pumps.

(Right) Exterior view of the above pipe line station. Building costs are at a minimum because of smaller structures, lightweight materials, absence of heavy cranes, craneways, etc.

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ply 36 communities in southwest Louisiana.

There were no new major interstate pipe lines constructed between 1932 and 1941 when the demand for natural gas increased as a result of our country's preparations for national defense and war. During those eight or nine years, however, there were large additions to the original interstate natural gas pipe line facilities, principal among which were:

The addition of a 1000-hp. compressor and 12 miles of 18-in. pipe line to the Northern Natural Gas Company's system in the Panhandle field in 1936 and 1937.

The erection in 1939 by Consolidated Gas Utilities Corporation of a 1600-hp. compressor station at Twitty, Texas.

The addition in 1940 of 1650-hp. of compressor units and a dehydrating plant at the Sneed station of the Panhandle Eastern Pipe Line Company, and the erection of a new compressor station at Hansford equipped with compressors having 4280 hp.

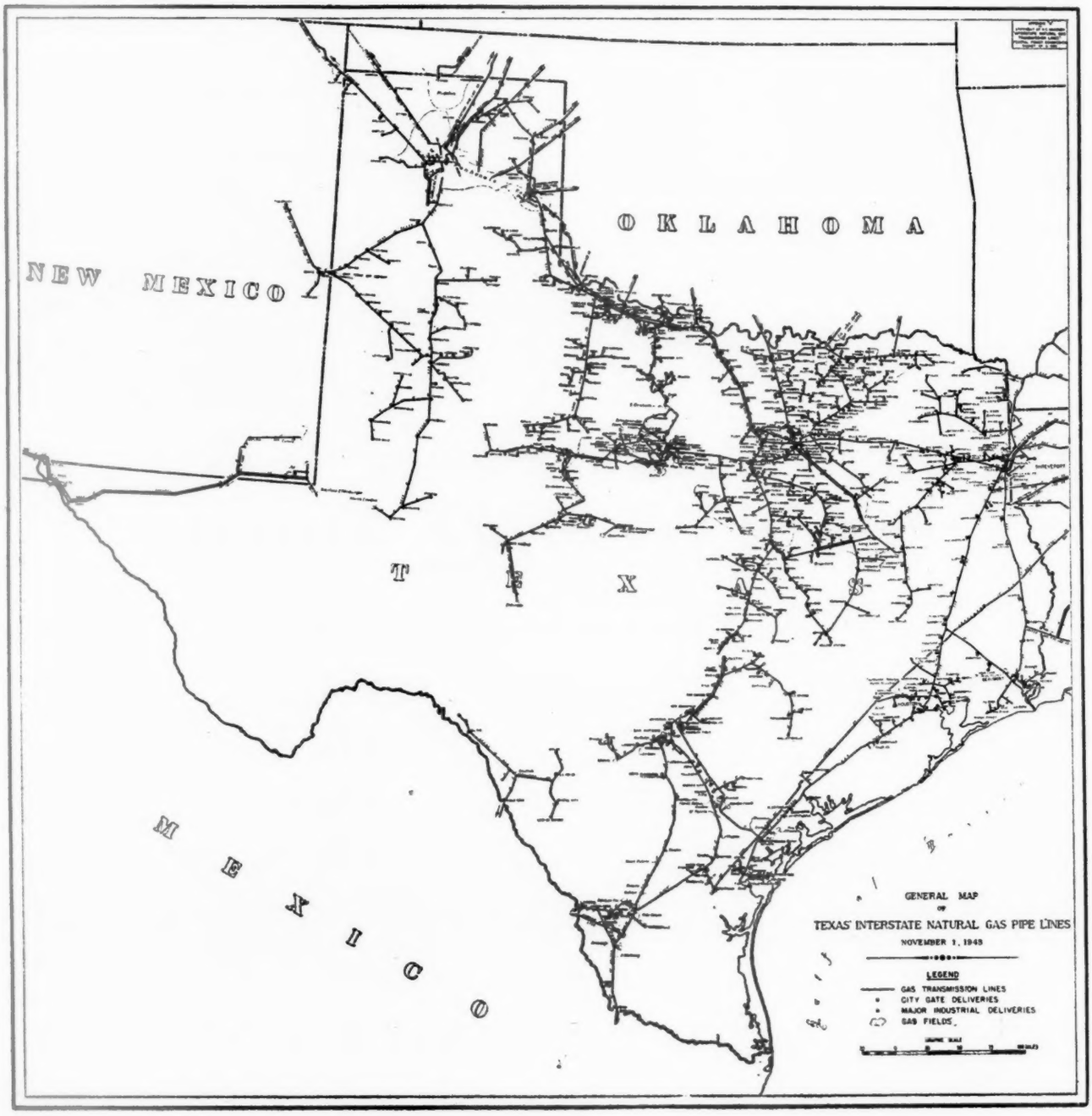
The construction in 1940 of a 10-in. line from the Joaquin field in Louisiana to connect with the pipe line to Beaumont, Texas, which was constructed in 1924.

There has been a substantial expansion of Texas' interstate pipe line facilities since 1941, occasioned primarily by the increased demands for natural gas as a result of our country's war effort. The facilities constructed during these years consist of:

A 14-in. pipe line constructed in 1941 by Southern Natural Gas Company from the Joaquin field in East Texas and the Logansport field in Louisiana to the Monroe field in Louisiana to supplement deliveries from that field to that company's pipe lines into Mississippi, Alabama, and Georgia. That company's lines east of Monroe are now being looped to substantially increase its transmission capacity.

In 1941 Texoma Natural Gas Company built a compressor station and gasoline plant in the Panhandle field and a 26-in. line from that station to

APPENDIX "A"



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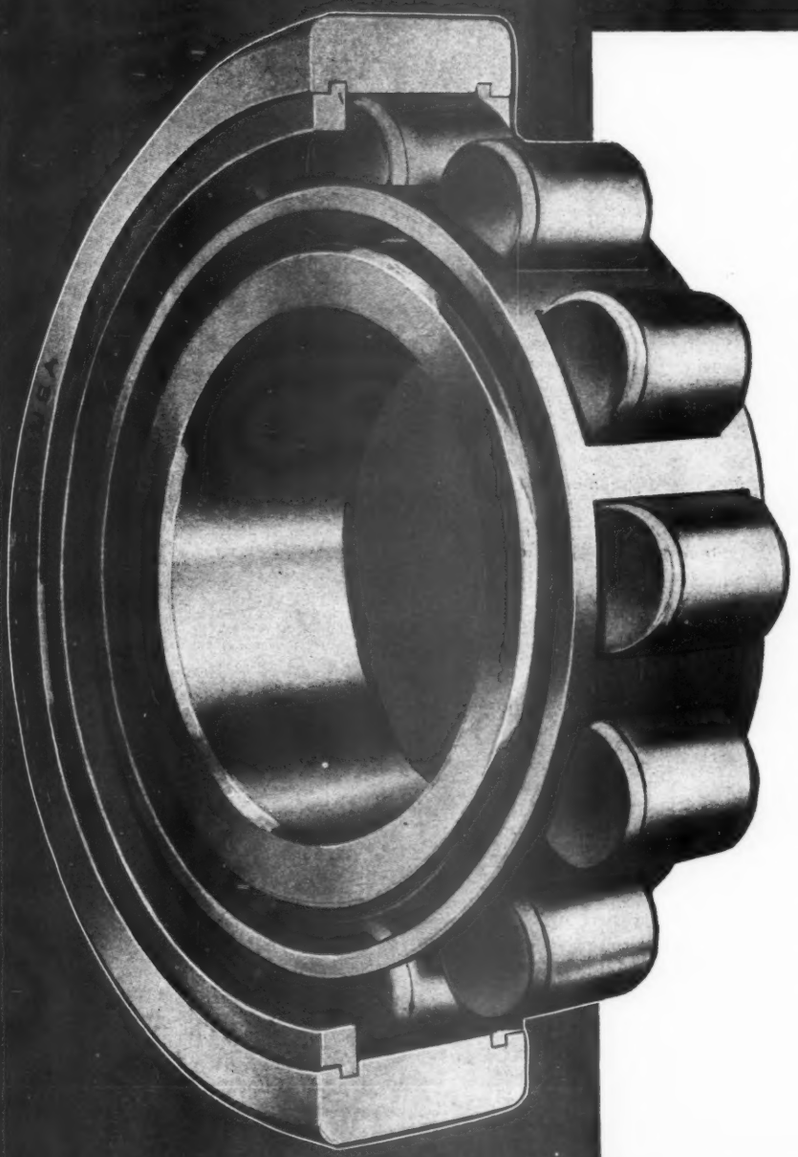

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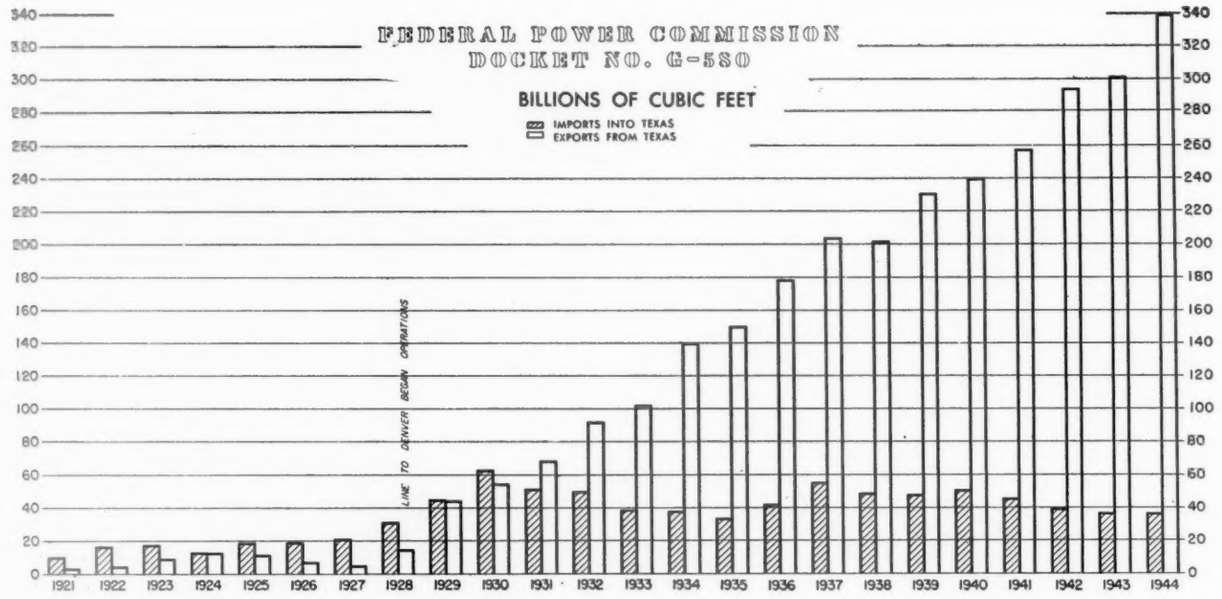
APPENDIX "B"



connect with its original 24 in. line. In the same year Natural Gas Pipeline Company of America looped approximately one-half of the length of its system to Chicago with 26 in. pipe. The two companies now have a joint application before the Federal Power Commission covering the installation of a 5000-hp. compressor station in the Panhandle field and 312 miles of 26 in. loop line between the field and Chicago. Those facilities will further increase the capacity of that system to meet the demands of that market area.

The Panhandle Eastern Pipe Line Company began the construction of additions to their system in 1942. In that year they added 2500 hp. compressor capacity to their Sneed station in the Panhandle field and 1300 hp. to the capacity of their new station in Hansford, Texas. In 1943 they added 3200 more compressor horsepower to the Sneed station and 3200 hp. to the Hansford station. In 1944 they constructed 15 miles of 22 in. pipe line to obtain gas from the gasoline plant of the Phillips Petroleum Company and added another 1600 hp. of compressor capacity to the Hansford compressor station and constructed 33 miles of 22 in. pipe line looping their system in Texas. The original 24-in. line between Hugoton field and Indianapolis has now been looped throughout its entire length with 22 in., 24-in. and 26-in. pipe. It has also been extended from Indianapolis to Detroit and other large cities in Michigan.

In 1943 and 1944 Consolidated Gas Utilities Corporation erected a 1950 hp. compressor station in the East Panhandle field.

Northern Natural Gas Company in 1943 and 1944 added 2000 hp. of compressor capacity to their compressor station in the West Panhandle field.

The Tennessee Gas and Transmission Company constructed in 1944 a 24-in. pipe line from the Agua Dulce field in South Texas to Charleston, West Virginia, to supplement the declining supplies of gas from the Appalachian field.

United Gas Pipe Line Company has completed a 24-in. pipe line from the Carthage field in East Texas to Monroe, Louisiana, to supplement and conserve production of gas from the Monroe field and to transport additional gas between the Carthage and Monroe fields for the Tennessee Gas and Transmission Company.

Application has been filed with the Federal Power Commission, by the El Paso Natural Gas Company, to loop its line from the Permian Basin fields in Texas and New Mexico, to Tucson, and extend it to California in order to initially transport 125 million cu. ft. of casing-head gas per day to markets in California which is estimated by the El Paso Company to increase to over 200,000,000 cu. ft. per day. The plans for that project also provide for a line from the South Hugoton field to supply the necessary firm basic supply for the extended El Paso System.

Thus we find that, until the fall of 1927, Texas' interstate natural gas pipe lines were constructed to bring natural gas into Texas to supply many Texas communities which had no gas facilities and also to supply power plants and industries with the natural gas needed for their operation and their growth. We also find that with few exceptions the large interstate pipe lines which were constructed between 1928 and 1944 were out of the Panhandle field. We find further that there was a substantial expansion of the transmission facilities out of the Panhandle field, as a result of the expansion of our nation's industry and its overall economy during the war years from 1941 to date.

We also find that without exception Texas' interstate pipe lines, whether they were built to import or export gas, were constructed to take gas from areas where there was a large potential production of gas from large reserves which had local markets which were insufficient to support drilling investments and to satisfy the royalty owners; also, that such lines were constructed to areas where a substantial and growing market existed for natural gas.

I have here a trend chart which shows a comparison between the volumes of gas imported into Texas and Texas gas exportations, a copy of which is hereto annexed as Appendix "B"; the basic data from which this chart was prepared are set forth on Appendix "C". It is noteworthy that from 1907 to 1920 Texas did not export any gas but imported substantial quantities; also that between 1921 and 1941 Texas imports of natural gas far outranked its export thereof. It should be further noted that Texas has continued to import in the neighborhood

APPENDIX "C."

Year	Imports into Texas, M. cu. ft.	Exports from Texas, M. cu. ft.
1921	9,790,000	2,953,000
1922	16,186,000	4,012,000
1923	17,154,000	8,652,000
1924	12,478,000	12,278,000
1925	18,494,000	10,881,000
1926	18,592,000	6,797,000
1927	20,456,000	4,573,000
1928	30,771,000	14,043,000
1929	44,538,000	43,901,000
1930	62,396,000	54,116,000
1931	51,010,000	67,958,000
1932	49,347,000	91,535,000
1933	38,274,000	101,537,000
1934	37,635,000	139,564,000
1935	33,054,000	149,723,000
1936	41,476,000	177,949,000
1937	54,874,000	203,315,000
1938	48,224,000	211,094,000
1939	47,230,000	230,096,000
1940	50,206,000	239,450,000
1941	45,060,000	257,291,000
1942	38,755,000	273,404,000
1943	36,200,000	300,735,000
1944	36,046,000	338,777,000

From Bureau of Mines "Minerals Handbook" through 1942; years 1943 and 1944 from Texas R. R. Commission records.

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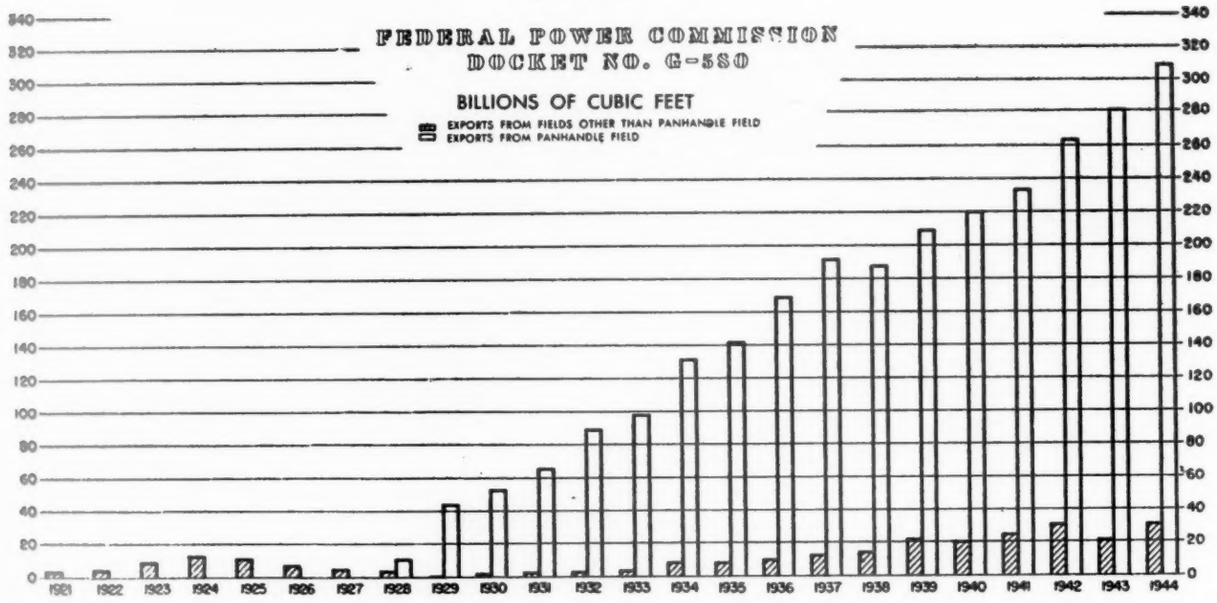
APPENDIX "D"



of 50 billion cu. ft. of natural gas each year since 1930.

A third chart shows the division of Texas gas exportations as between the Panhandle field and other gas fields, a copy of which is hereto annexed as Appendix "D". The basic data from which this chart was prepared are set forth on Appendix "E" hereto. From it we note that Texas' principal exports of gas have been from the Panhandle field. It is pertinent, therefore, to look into the history of the operations in the Panhandle field and note the effect of the exportation of natural gas from that field.

In 1927, when the first line out of the Panhandle field went into operation, an estimated 505 billion cu. ft.[2] of gas were produced from that field to be stripped of its gasoline content and to raise the oil also produced from that field. Of that amount, 8.8 billion cu. ft. were taken by pipe lines and utilities and 11.2 billion cu. ft. were used in the field, but the balance of 485 billion cu. ft. was blown into the air. Thus we find that in 1927 there was a tremendous production of natural gas from the Panhandle field which was available for beneficial use in large quantities if it could be economically transported to the nation's cities and industries.

Texas Railroad Commission's data show that 824.7 billion cu. ft. of gas were produced from the Panhandle field in 1944. Pipe lines took 464 billion cu. ft. of that amount. Carbon black plants used 262 billion cu. ft.; 95 billion cu. ft. were used in the field, and 3.7 billion cu. ft. were vented to the air.

Through the operation of pipe lines out of the Panhandle field the gas taken from that field has not only been useful in producing oil and natural gasoline, but the residue gas from these operations has been used to economic and social advantage (1) by supplementing waning supplies of natural gas, from other sources, to people who had become accustomed to its use and had investments in appliances and equipment to utilize the product, and (2) by supplanting higher cost fuels and labor consuming fuels in areas that had not theretofore had natural gas.

The businesses of the five long-lines taking gas to the Middle West and the East have been developed to the point where they are now operating at close to capacity all through the year. During the summer months, however, a small portion of their line capacities is utilized for the sale of interruptable gas.

The 24-in pipe line of the Tennessee Gas and Transmission Company was built to supply established natural gas systems that have established markets far in excess of their gas supplies. This transmission line out of Texas has, therefore, also been operated at approximately 100 per cent load factor during the past year. It went into service November 1, 1944.

Since there is a large and growing demand for natural gas for residential and industrial uses, it is significant to note that Texas' gas reserves are estimated at 82 trillion cu. ft. today, whereas the proved reserves, January 1, 1931, in the entire United States were estimated[3] at only 46 trillion cu. ft.

Current trends in the operations of interstate natural gas pipe line companies are bringing about a balance between natural gas supply and demand. I have here a chart showing representative trends in the volumes of gas purchased by representative Texas' interstate gas pipe lines in comparison with the volumes of gas produced by the same interstate pipe line companies and their affiliates, a copy of which is hereto annexed as Appendix "F". The basic data from which this chart was prepared are set forth on Appendix "G" hereto. Increased markets for Texas' natural gas, as shown by this chart, have resulted in a substantial increase in the volumes of gas purchased from non-affiliated producers.

In recent years, Texas' interstate natural gas pipe lines have added to their natural gas reserves largely by the acquisition of long-term contracts for the purchase of gas from non-affiliated producers. This is an aid to the conservation of the State's natural gas resources, and also is an economic advantage to the State and to those who search for gas and oil and go to the land owners under whose properties gas is found.

2. Estimate by Victor Cotner and H. E. Crum in *Geology of Natural Gas*, 1935 Edition, by American Association of Petroleum Geologists.

3. By Earle P. Hindes, geologist, Cities Service Company.

APPENDIX "E."

Exports of natural gas from Texas.

Year	MM. cu. ft. exports from Texas		
	Total	Panhandle	Rest of Texas
1921	2,953	..	2,953
1922	4,012	..	4,012
1923	8,652	..	8,652
1924	12,278	..	12,278
1925	10,881	..	10,881
1926	6,797	..	6,797
1927	4,575	..	4,575
1928	14,043	10,506	3,537
1929	43,901	43,755	146
1930	54,116	52,400	1,716
1931	67,958	65,611	2,347
1932	91,535	88,894	2,641
1933	101,537	97,977	3,560
1934	139,564	131,379	8,185
1935	149,723	141,685	8,038
1936	177,949	168,483	9,466
1937	203,315	191,187	12,128
1938	201,094	187,137	13,957
1939	230,096	208,640	21,456
1940	239,450	219,547	19,903
1941	257,291	233,066	26,225
1942	293,404	262,943	30,461
1943	300,735	279,999	20,736
1944	338,777	308,364	30,413

Compiled from Bureau of Mines "Mineral Handbook"; year 1943 from Annual Report of Gas Utilities Division of the Texas Railroad Commission; and year 1944 from letter and schedule dated July 20, 1945 from Texas R. R. Commission.

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If pipe lines can continue to offer markets for enough gas at a price which is adequate to pay out the producer's investment in his leases and wells and yield a return thereon, these interstate pipe lines have and will continue to contribute to the welfare and economy of the State of Texas.

The interstate pipe lines operating in Texas and the other southern states serve areas where the winter heating season is shorter, and where outdoor temperature variations during the heating season are more pronounced than they are in the North. Our peak day deliveries to the city of Houston, for example, were nearly six times the volume of our average daily deliveries in August, 1945. Likewise, our industry is not as dense or as diversified, and our per capita incomes are not as high as they are in the Midwest and East. As a result, natural gas pipe lines in the South have not been able to develop system annual load factors which are higher than 75 per cent capacity.

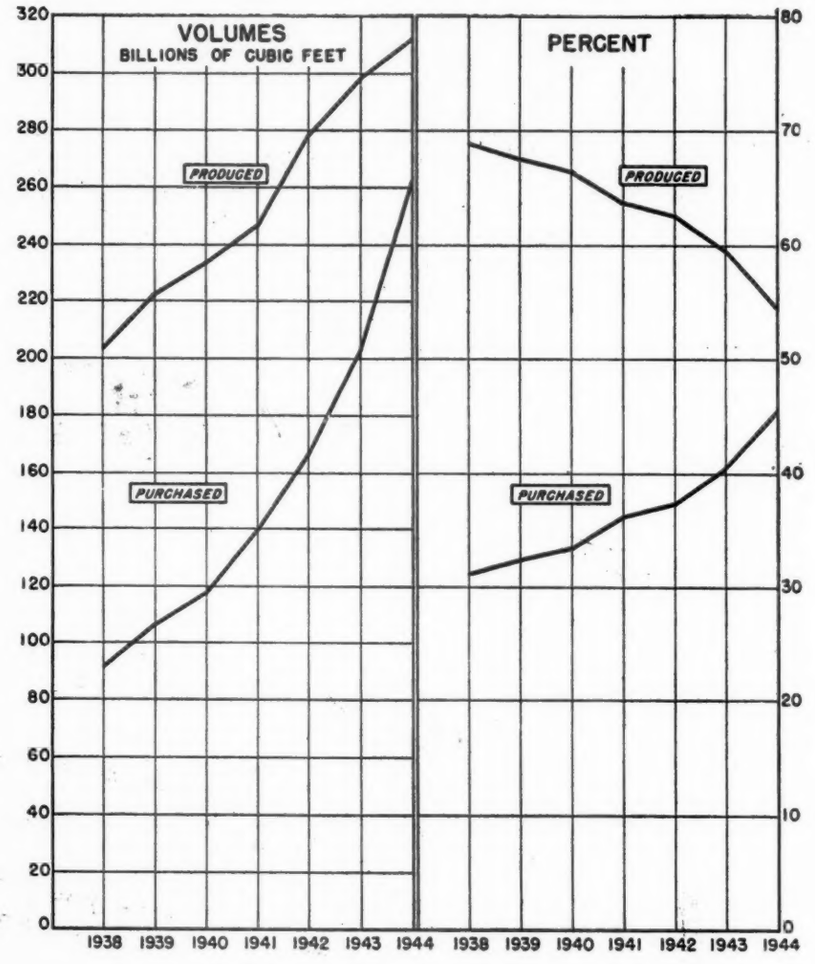
There are, however, prospective developments in the use of gas which, if they can be realized, will substantially improve the annual load factor of the interstate pipe lines in the South and Southwest. One of these developments is the use of gas for summer air-conditioning in homes, business establishments, office buildings, hospitals, and hotels. Studies which have been made of the market for summer air-conditioning show that more gas is required for cooling than for heating the same space.

Gas summer air-conditioning has been aggressively promoted, with the result that 234 gas-fired summer air-conditioning units are now in use in the South. Postwar sales plans include a program of further aggressive promotion of this service. As the electric industry continues to sell electricity for refrigeration, ventilation, and air-conditioning and continues to use gas for power house fuel, that also increases our summertime gas sales.

Economically, the operation of Texas' interstate natural gas industry have been widely beneficial. The gas imported into Texas has, for 15 or more years, supplied in part the residential, commercial, industrial, and power house fuel needs of the area east of a line drawn between Fort Worth and Houston. Imported gas brought that service to many large and small communities that never before had natural gas, and supplied those needs at a time when there was not enough natural gas production in Texas to serve its people, thereby adding to the comfort and advancement of this area and producing payments to land owners, employment to many people and the taxable income of the State and Counties from which those supplies had their source. In addition, imported gas has served El

APPENDIX "F"

Trend of gas produced and purchased in Texas by interstate gas pipe line companies.



APPENDIX "G".

Trend of gas produced and purchased in Texas by interstate pipe line companies

Year	Total, M. cu. ft.	Produced	Purchased	Per cent	
				Produced	Purchased
1938	295,663,424	203,668,004	91,995,420	68.9	31.1
1939	329,074,515	222,414,888	106,659,627	67.6	32.4
1940	350,626,593	233,079,415	117,547,178	66.5	33.5
1941	386,611,751	246,604,759	140,006,992	63.8	36.2
1942	444,864,799	278,764,704	166,100,095	62.7	37.3
1943	502,006,604	298,945,730	203,060,874	59.6	40.4
1944	574,016,069	312,107,171	261,908,898	54.4	45.6

Data obtained from Texas interstate gas pipe line companies.

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Paso since 1928. The population of Texas' "industrial cities" served in part by imported gas has increased 135 per cent since 1920. Its industry and wealth have grown proportionately. There is no question in my mind about the availability of natural gas having a bearing on that economic development.

Data are not available on all Texas' interstate gas operations and their effect on the economy of the State. but incomplete statistics show that Texas' interstate pipe lines paid:

$4,4 0,000 to over 2000 employees in Texas in 1944.

Over $9.100,000 for gas purchased in Texas in 1944.

Over $1.800.000 in royalty and rental payments on the gas they produced in Texas in 1944.

Over $700,000 in property taxes.

Over $820,000 in other taxes.

Thus the economy of Texas has benefited by the export of a natural resource which. prior to the advent of interstate pipe lines, was not productive of any revenue.

The Bureau of Mines in its report on "Natural Gas In 1929" has this to say about the beneficial use of natural gas in steel mills: "Natural gas has been used by steel mills in the vicinity of Pittsburgh for many years. The ease of temperature control makes it particularly adaptable for use in melting and in the heat treatment of metals. Furthermore, it has been proved that the refractory life of furnaces is longer when natural gas is used. Natural gas is practically free from sulphur, and this quality is of prime importance in the manufacture of steel, glass, and ceramic products. The even temperature obtained through the use of gas results in fewer 'seconds' and rejections." As natural gas has become more widely available there has been great advancement in the art of using it in the manufacture of steel and many other articles. The use of natural gas has enabled the manufacture of better things at lower cost thus benefiting our whole economy.

In order to make these economic benefits possible, over 620 million dollars have been invested in the physical properties of the interstate pipe line companies which operate in and out of Texas. I have no idea how much money has been invested in the production properties, gasoline plants, and other processing equipment which have been constructed and operated in Texas to supply its interstate natural gas pipe lines.

The interstate natural gas industry frequently operates in competition with Texas' intrastate pipe lines which are constructed to market gas which is a by-product of gasoline plants whose primary business is the extraction and sale of valuable quantities of natural gasoline or other liquid hydrocarbons. The interstate natural gas industry competes with other fuels—fuels that do not have to be transported solely by pipe line but can be moved in a bucket, barrel, sack, truck, barge, railway car or pipe line. It has shown that such competition has been broadly beneficial to society and the economy of the areas served by Texas' interstate pipe lines.

It has been shown that increasing gas reserves in Texas are adequate to support both the intrastate and interstate natural gas pipe line industry for a long time, and that state regulation of the natural gas and petroleum industry is working to conserve those gas reserves. Regulation of the production and gathering of gas should therefore be left to State Regulatory bodies.

Technological progress in the discovery and development and conservation of natural gas reserves, and in the construction and operations of interstate natural gas pipe lines with their sources of supply in many fields in and out of Texas have put an end to the days when a community, or an industry, lost its essential supply of natural gas because of the exhaustion of local natural gas fields.

The American public demands a free choice of everything it uses. It will not like being told it cannot use natural gas because it lives in a coal producing area. It likely sees in the future development of atomic energy, powerful sources of energy which may eventually result in the obsolescence of natural gas as a fuel. In the years that intervene before new sources of energy are developed we should be untrammeled in the use of our resources so that our research can produce better things for our future generations out of the resources that will be available then. ★★★

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CHARLESTON, WEST VIRGINIA

Engineer's Viewpoint on Design of Compressor Cylinders for High Pressure Gas Compression*

By **H. A. GEHRES,** Vice President, The Cooper-Bessemer Corporation

In recent years a great amount of development has taken place in the construction and use of high pressure compressor cylinders in the range of 300 to 6000 lb. per sq. in. pressures for various purposes. The chemical industry has been responsible for a large amount of this development in the production of ammonia, methelene, etc., and has used many compressors operating in a range of from 5000 to 15,000 lb. final pressure. It seems that there is no limit to what can be accomplished in the way of rearranging the molecules of various combinations of gases to manufacture different products when the proper pressure and temperature in conjunction with the proper catalyst is used. We look to further great strides in the use of high pressure compressors for this kind of work in the future.

In the oil and gas industry the use of high pressure compressors is increasing at a very rapid rate. In the transmission of natural gas through pipe lines, covering a period of about 45 years, line pressures have steadily increased until 700 to 1000 lb. lines are common for consideration. Conservation measures are gradually causing more and more gas to be returned to the formation, either directly from the separators, or through cycling plants where the gasoline content is recovered during the process. Pressures for this work depend on the depth of wells, the permeability of the sand, length of lines, etc., and pressures of from 4000 to 6000 lb. are not uncommon. Higher pressures are undoubtedly coming in the future as deeper structures are discovered.

For main gas pipe line work the compressor units are usually gas engine driven of from 800 to 1500 hp. For many years these were of the horizontal double-acting twin-tandem type with direct-connected horizontal compressor cylinders. These cylinders were of the double-acting type, the old models having poppet valves; however, for the past 25 years they have been mostly of the plate type, which allow higher rotative speeds. These cylinders are of cast-iron construction in the lower and medium pressures but often steel construction in ranges of 700 to 1000 lb. A typical medium pressure design is shown on Plate 1, consisting of a central body usually with a removable wet liner and two heads containing the valves with passages back to central intake and discharge connections.

Of recent years angle-type engines have been introduced running at higher speeds and both four and two cycle. Compressor cylinders, both of the design shown in Plate 1 and a lower cost design without removable wet liner (although a dry liner can be used if desired) and with valves in the main body and either one or two very simple removable heads as per Plate 2 have been used on these higher speed engines and motor-driven compressors.

For the next higher pressure range of compressors for repressuring, cycling, and process work, double-acting cylinders are also used but certain disadvantages develop. It becomes unsafe to use cast iron for such pressures and it becomes very difficult to make steel castings with the intake and exhaust passages as well as valve openings cast in one piece as per Plate 2 and the junction of the passages with the flange connections becomes the weakest part of the design. To make a design as per Plate 1 for such pressures would involve a very difficult gasketing job between head and cylinder body, particularly around the intake and discharge passages.

Plate 3 shows a design of double-acting cylinder capable of covering a range of from 1000 to 2000 lb., which obviates these difficulties. The two heads are of steel castings as is also the outside jacket of the body. This body is shrunk on to several circumferential ribs of a cast-iron liner, the spaces between forming a water jacket. Thus the wearing qualities of a cast-iron bore are combined with the strength of the steel jacket. The pressure is held by a copper gasket between the head and liner while the water is sealed by means of a gland and rubber grommet. The inlet and discharge piping is flanged directly to the heads, thus avoiding all flat gaskets. This piping can be in the form of a U connection with common outlet as per Plate 4, Fig. 1, or individual outlets extending down to headers below as per Fig. 2. This is an excellent design for strength but does have the disadvantage of requiring the breaking of a pipe joint to remove a head.

For the next higher pressure range up to 4500 lb., it is advisable to go to forged-steel bodies with dry cast-iron liners shrunk in. Such a double-acting cylinder is shown in Plate 5. The body is a heavy walled steel forging with a light steel band welded to the outer periphery forming a water jacket. A solid forged-steel head with unloader valve is inserted in the outer end and a high pressure rod packing in the other. The suction and discharge passages are drilled into the body and provided with adequate forged-steel flanges. The piston is of solid cast iron. The rod is 1045 steel for the lower end of the range but it is desirable to case harden it for the upper end of the range.

For still higher pressures for a given horsepower the cylinder becomes so small in relation to the diameter of the piston rod that the displacement on the rod end is so small in relation to the other end that it scarcely seems worthwhile to provide valves, gaskets, etc., for the rod end and also subject the packing to the full discharge pressure. To obviate these disadvantages, single-acting cylinders of many different designs are used.

One of the simplest forms of single-acting cylinders is made just like an outside packed plunger water pump. (See Plate 6.) The plunger rides through a packing but free of the cylinder wall except for a band of bronze or other anti-friction material which carries the weight and centers the plunger. Intake and discharge valves are provided at opposite end from the packing. The advantage of this design is that a hardened plunger can be used that is much easier and less expensive to make than a hardened liner. This type is usually only used on very high pressures, from 5000 to 15,000 lb., where there would be practically no differential between rod and piston, if a double-acting design were used.

The disadvantages are that the entire circuit of pressures from suction to discharge and back again must be carried on a rod packing giving no relief at all from relatively high pressures. It is usually considered easier to maintain piston rings than rod packing. Another disadvantage is that the entire circuit of pressures must be carried on the bearings of the prime mover whereas with a double-acting cylinder whatever area is left on the rod end times the pressure at any point in the stroke is balancing that much of the load on the other side of the piston. Another disadvantage is that the heat of compression is exposed to the full length of the rod inside the cylinder.

The next one in simplicity is similar but has rings on the plunger so that the packing only has to handle leakage as per Plate 7. The space between the plunger and packing is vented off either to atmosphere or to some lower stage of pressure.

The two designs, Plates 6 and 7, have an unique valve arrangement (See Plate 8.) Both suction and discharge valves are in one piece and held in the end of the cylinder by a simple cylinder head. Groove A and corresponding side opening constitute the inlet passage and Groove B the discharge. C is a combination valve seat with a sealing ring D

*Presented before California Natural Gasoline Association, September 25, 1945.

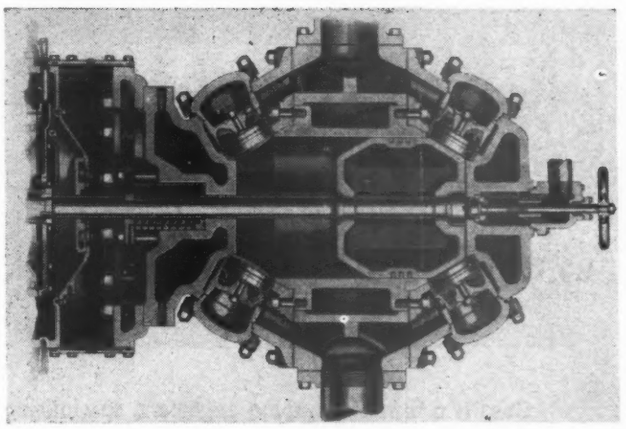


PLATE 1.

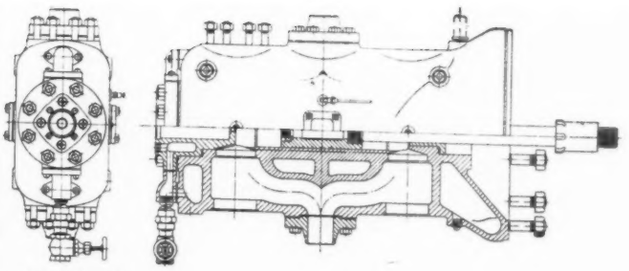
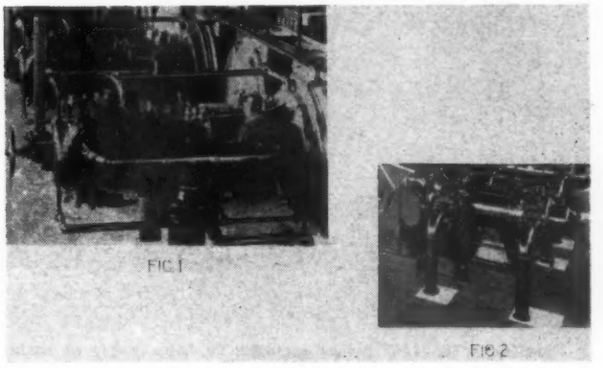


PLATE 2.



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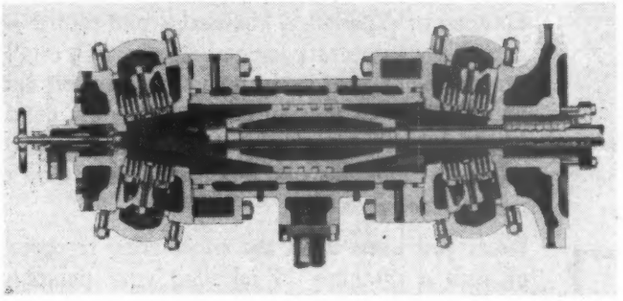

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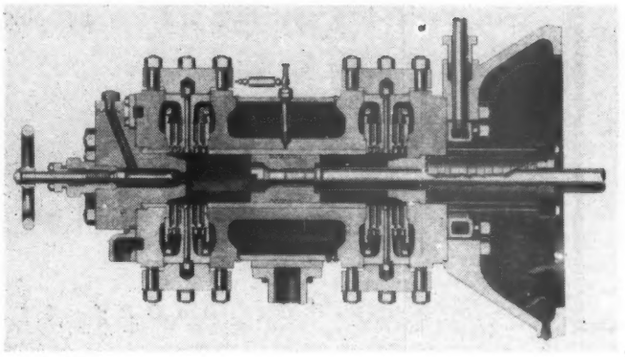

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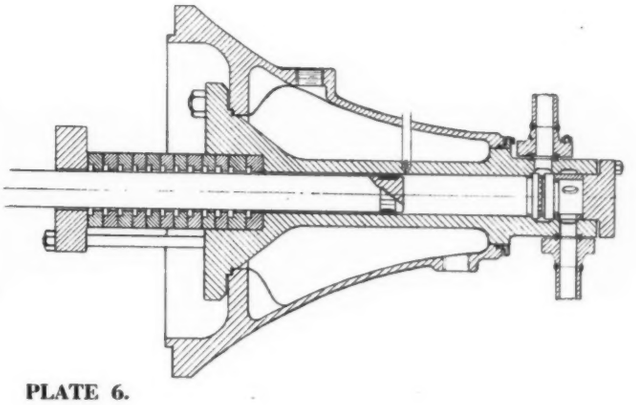

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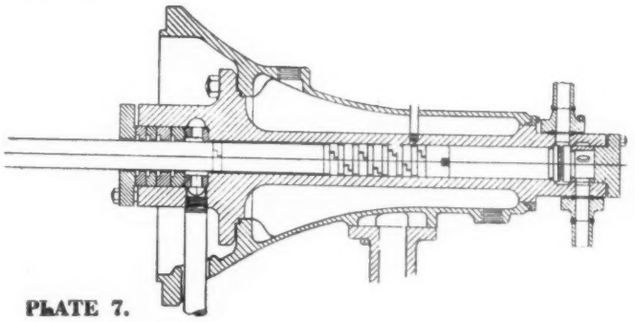

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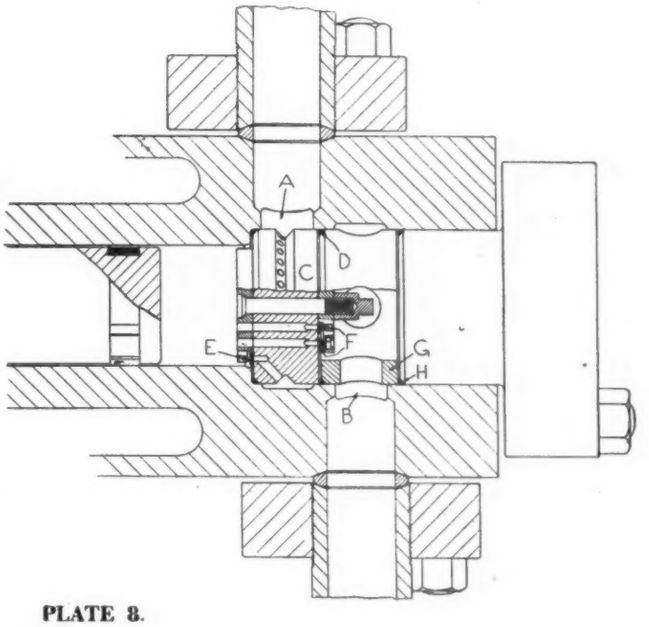

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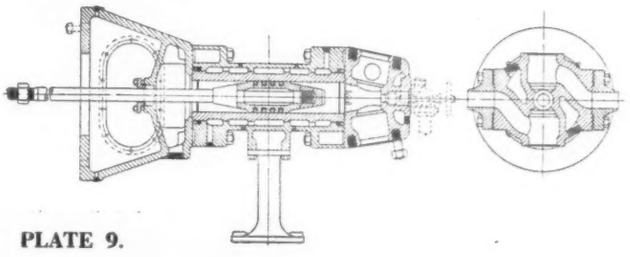

PLATE 9.

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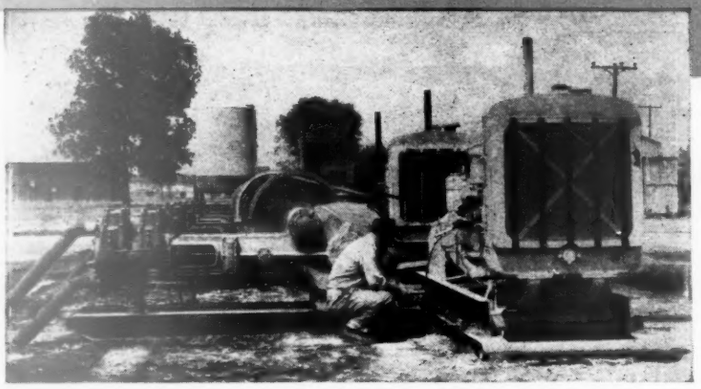
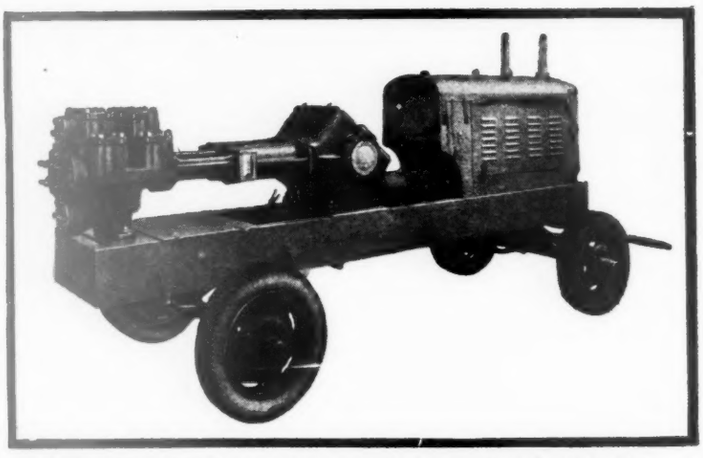
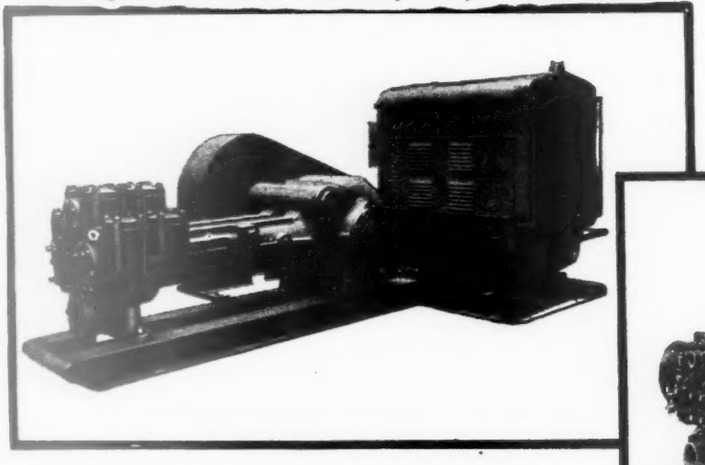
Priceless experience, invaluable records



Battery of Fig. 1742 pumps operating 24 hours a day on crude oil line in the Illinois field.



Gaso Fig. 2050 mounted on trailer—ready for export to South America.



Gaso Fig. 1743 Duplex Piston Power Pump mounted on skid, complete with power unit.

Gaso is a firm of pumping engineers, specializing in the solution of oil-industry pumping problems. To such problems, Gaso brings a matchless combination of experience, knowledge and records—experience with every imaginable pumping condition; knowledge of every type of power unit and hookup; records that include the minutest detail of all of the thousands of installations made since the Gaso company was organized, more than a quarter-century ago.

When you draw upon the engineering resources of such a company in fulfilling your pumping needs, you are sure of everything that contributes to the results you are seeking—positive performance, trouble-free operation and low pumping cost.

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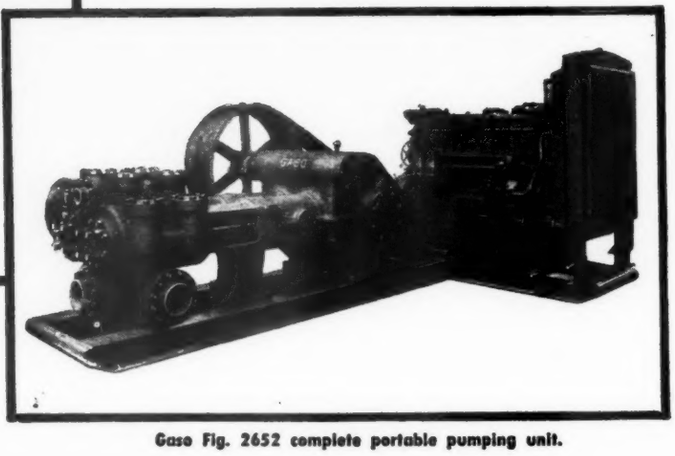

Gaso Fig. 2652 complete portable pumping unit.

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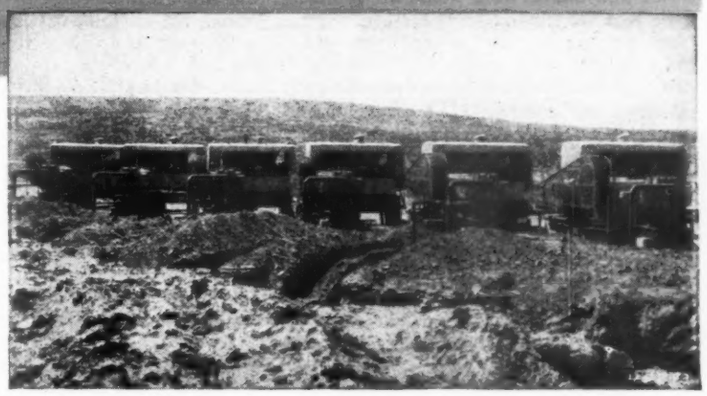

Six Fig. 1742 Gaso Pumps powered by two Diesel engines and four natural gas engines, operating under severe dust conditions.

The completeness of the Gaso line, moreover, assures a type and model precisely fitted to your specific needs—a pump that embodies not only the most advanced engineering, the sturdiest parts and the utmost in precision manufacture, but the priceless know-how of an organization which, since 1916, has been concentrating all of its skill and effort upon the creation of dependable oil-industry pumping units.

The Gaso engineering department is dedicated to your service. Please feel free to call for any desired suggestions or recommendations.

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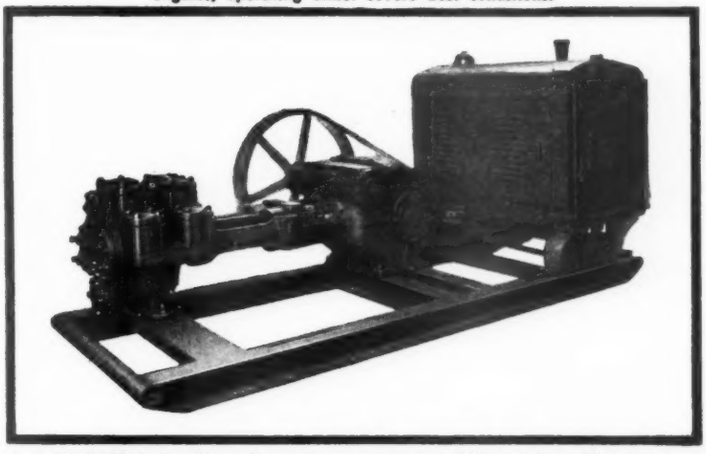


Gaso Fig. 1550 Duplex Piston Power Pump mounted on skid, complete with power unit.

PUMPS

industry need

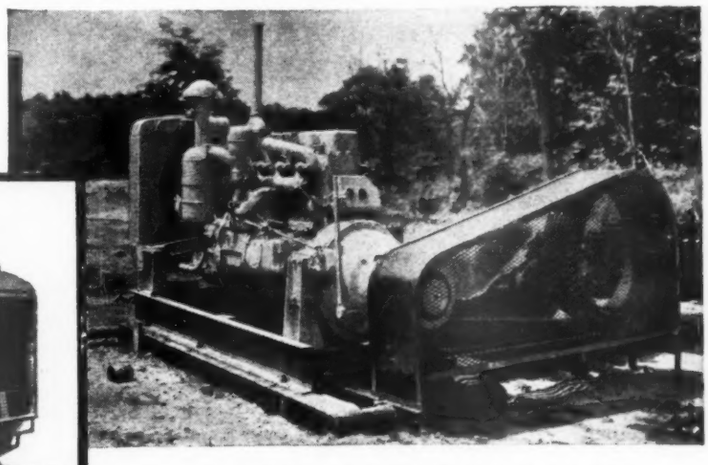
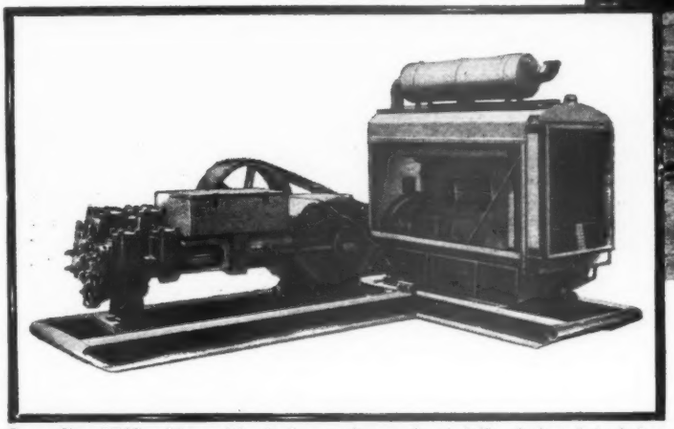


Fig. 1742 Gaso Pump powered by Diesel engine on midwestern pipe line.



Gaso Fig. 1742 with multi-cylinder engine and specially designed tool box.

between suction and discharge. A series of diagonally drilled holes connect passage A to the valve port and suction valve E with its guard and springs covers the port. The discharge goes through a series of holes to the opposite side of C where they are covered with discharge valve F and corresponding guard and springs. A spacer G with sealing ring H transmits the pressure from the head to the valve seat so that all joints are in series and one bolting holds all joints. This is a very satisfactory design, both from the standpoint of accessibility and the fact that only small holes need be drilled laterally for inlet and discharge passages as compared to what they would be if lateral valves were used. The clearance volume is also a minimum.

Where there is a differential between the diameters of the rod and piston required but not enough to warrant putting in valves, etc., for use double acting, a very good design can be made from standard double acting parts. Plate 9 shows such a cylinder. The head, body, and piston are the same as shown on Plate 3. In the place of the rear head is a spacer piece containing a simple low pressure packing. The space between will have a displacement equal to the differential area between rod and piston times the stroke. This space has an opening that can be used to vent to atmosphere or some low pressure stage or it can have installed in it an outwardly opening check valve which causes a partial vacuum in the surge chamber and still further reduces the leakage through the packing. By putting a pressure packing in the surge chamber a pressure can be maintained in this chamber that will counterbalance any desired portion of the load on the opposite side of the piston.

The most efficient type of single-acting compressors from several standpoints is the design using a suction valve in the piston.

Plate 10 shows a very simple type of piston inlet compressor for medium pressure. The body with both inlet and outlet connections is cast in one piece. A dry liner can be used or not as desired. Gas enters through inlet port A, passes through piston valve, through discharge valve mounted in end of cylinder bore, and out through discharge passage B. It can be readily seen that this design gives a maximum of valve area combined with a minimum of clearance volume. The entire piston area is used for a suction valve and the entire end of the cylinder is used for discharge valve while, having no valve pockets, the only clearance volume existing consists of the spaces in the valve guards and not over 1/16-in. lineal clearance between the two guards at the end of the stroke. If desired a clearance pocket valve opening can be used through the center of the discharge valve where the least valve area would be lost.

For very high pressures where it is necessary to use forged parts a design as shown in Plate 11 can be used. A forged barrel A is mounted in a cast-iron jacket B, the space between forming a water jacket. C is an inlet pipe, and a suitable packing to withstand suction pressure only is mounted in opening D. The outlet connection E is drilled in the forged barrel and fitted with high pressure flange.

These two types are not only very efficient for valve area and clearance, but they have the same advantage as the double acting in having the differential area between piston and rod balanced by the suction pressure. During the suction stroke the only loading on the bearings is the suction pressure times the area of the rod, and during the dicharge stroke is the loading of the discharge pressure times the area of the piston less the differential area between piston and rod times the suction pressure. An added advantage is that the rod packing never has to handle any pressure higher than suction pressure. Another advantage is that the clearance volume can be changed from a minimum to any desired amount by simply screwing the piston rod back into the crosshead.

Another type of high pressure compressor, although not used in large numbers, deserves to be mentioned. This compressor is called a "recirculator." (See Plate 12.) It is used in process industries to return gases to the system, that have gone through a catalyst, without chemically combining. By the nature of this application the temperatures are high and the compression ratio very low. It is not uncommon to see a 4500 lb. discharge with a 4000 lb. suction, or a compression ratio of only 1.2 to 1. While single-acting compressors could be used it can be readily seen that high pressure would have to be carried by the bearings of the prime mover all the way around the cycle. This loading would at no time have any relief that would require larger bearings than ordinary and also the ultimate in lubrication methods. For these reasons most machines for this service have been built double acting with a balancing rod running out the opposite end from the crank. This makes a true double-acting compressor in that the displacement is exactly alike on both ends and the high suction pressure completely balances the corresponding amount of discharge pressure. The disadvantage, however, to this type is the addition of another set of high pressure rod packing. In this case the user must choose between two disadvantages: Practically unrelieved bearing loading, where the differential area between piston and rod is low and the suction pressure is high in relation to discharge, or an extra set of high pressure rod packing.

It has been previously mentioned that single-acting compressors similar to Plate 6 and Plate 7 have the disadvantage of loading the bearings without any balancing effect. Where the compression ratios are such as to require more than one stage of compression this can be overcome and gain all the advantages of both double and single-acting by combining two stages on one rod, one acting on one stroke and the other on the opposite stroke. Plate 13 shows such an arrangement. The compression space A is one stage and B is the higher stage receiving its suction from A's discharge. In this way, since the piston loading of A and B are approximately equal, the effect of balancing is exactly like a double-acting cylinder. It has the added advantage of greater compactness, one crank throw, connecting rod, etc., instead of two for two stages and the timing is always right since B is always taking suction while A is discharging, thus requiring a minimum of storage capacity between stages.

The following is a discussion of some of the detail problems in conjunction with compressor design arranged under individual headings.

● **Compressor cylinder cooling.** The requirements for cooling compressors also vary over a wide range. The only reasons for cooling are to prevent deterioration of the oil film on cylinder wall, prevent formation of carbon in piston rings and valves, prevent heat radiation to the surrounding air, and to obtain somewhat better efficiency as any heat that is given up to the jackets during compression is a saving of power. In many services the temperatures are so low that water cooling is not necessary. Certain others operating on low temperatures have water jackets to warm the cylinder bores rather than cool them to prevent fluid condensation on the cylinder bores, which would injure lubrication. In some straight gas pumping jobs the temperature of the incoming gas is so low that condensation would result if warm water were not kept in the cylinder jackets.

The chart on Plate 14 shows the increase in temperature with the compression ratio. Curve A is based on G. G. Brown's enthalpy curves for 0 60 gravity gas with the base pressure of 14.7 lb. per sq. in. abs. and the base temperature at 60°F. Curve B is based on perfect gas laws with the same base temperature and pressure. From this it can be readily seen that for very low compression ratios little or no cooling is required, while for the higher ratios cooling becomes very necessary.

● **Piston and rod loadings.** Piston loading, as far as stresses on the parts are concerned, is easy to determine. The peak differential pressure, viz., discharge pressure minus suction pressure, times the largest piston area likely to be encountered for a given horsepower, will give the maximum loading on rods, crossheads, etc. The piston rod is usually the highest stressed member so an area at the root of the thread that will give a stress of around 6000 lb. per square inch for 1045 steel will be adequate. The bearing situation, however, becomes entirely different because a duration factor must be introduced and these duration factors vary over a wide range. The longer the duration of the loading, the more opportunity there is for the oil film to be squeezed out and the more heat is generated in the bearing, which in turn lowers the viscosity of the oil in the bearing.

Plate 15 shows two sets of curves to illustrate this. A compressor cylinder is

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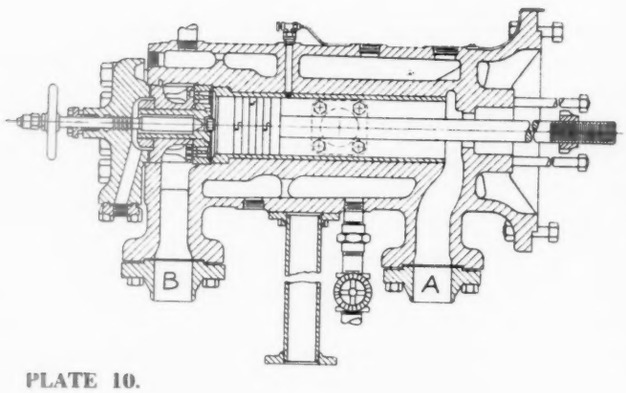


PLATE 10.

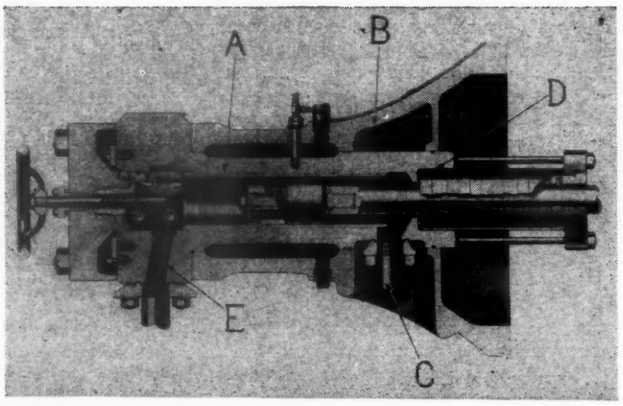


PLATE 11.

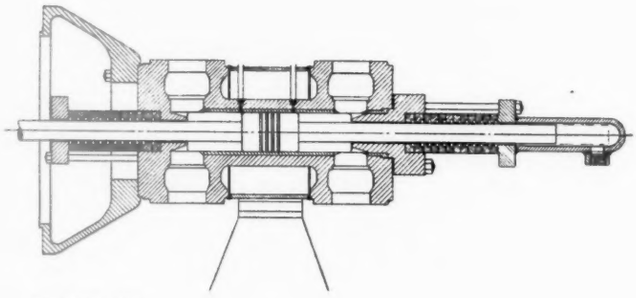


PLATE 12.

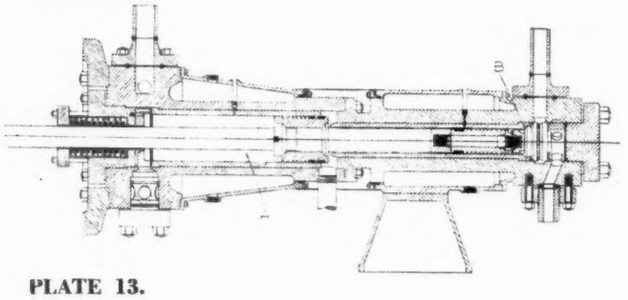


PLATE 13.

assumed to absorb 200 hp. at widely varying conditions. The cylinder size is assumed to be changed to meet these conditions and always absorb 200 hp.

Fig. 1 shows four curves for differential pressures from 250 to 1000 lb. for rod load and four curves for "mean indicated pressure" for the same differentials for compression ratios from 1.2 to 6. Observe that the rod load curve for 1000 lb. differential starts at 42,500 lb. for 1.2 ratio, drops to 22,500 at 2.4 ratio, and goes back up to 32,000 lb. at 6 ratio. The m.i.p., however, drops continuously from 900 lb. at 1.2 ratio to 326 lb. at 6 ratio. Neither of these can be used to determine bearing sizes.

Fig. 2 shows four curves for the same differentials and compression ratios but with the time factor added. The left-hand scale represents rod load times seconds duration. Referring to Fig. 1, the rod load at 1.3 compression ratio and 1000 lb. differential is 36,000 lb. At the minimum point or 2.4 ratio the load is 22,500 lb., or a ratio from high to low of 1.6 to 1. Referring to Fig. 2, the lb. per sec. diagram for 1000 lb. differential is 2600 for 1.3 ratio and 980 for 2.4 ratio, or a ratio from high to low of 2.65 to 1, or nearly twice the heating effect as if the bearings had been designed according to pressures only.

It is, therefore, very important to allow for the duration factor in designing bearings where all or a large portion of the load is for compressors that are likely to operate with a low compression ratio.

● **Cylinder liners, pistons, and rings.** The choice of materials for cylinder liners and rings is very much more important than material in a piston. As a usual thing a piston has a large area to ride on in proportion to its weight in the case of horizontal cylinders, and in the case of vertical cylinders there is no pressure at all on the cylinder wall as a result of piston weight. Compressors for the subject services, representing a great preponderance of the horsepower used, are driven from crossheads so that there is no connecting rod thrust to carry. In case the weight of a horizontal piston produces a cylinder wall loading that might be a little on the high side, it is an easy matter to build the piston with anti-friction bands that carry the weight and are not difficult to replace.

In the case of cylinders and piston rings, extreme care should be taken in the selection of materials. The unit pressure of the piston ring against the cylinder wall is almost up to the pressure of the gas in the cylinder. Only the leakage or blow-by past each ring has any counterbalancing effect. In the case of a 4000 to 6000 lb. cylinder we are expecting a piston ring to run against a cylinder wall with two to four times the unit pressure that we expect of the best constructed bearings, with anti-friction bearing material, hardened pins, shafts, etc., and with force feed flush lubrication. We expect all this to be accomplished with a very minimum of lubrication and in many cases a generous supply of pipe scale, sand, and other forms of dirt as well as water, hydrocarbon condensates, mineral seal oil, etc., coming through with the gas.

Most manufacturers of cylinders and rings have their own preferred analysis, particularly in the cast-iron field, so I will not attempt to give any specific analysis of iron but I will caution that any iron used for liners or rings should be as low as possible in free ferrite.

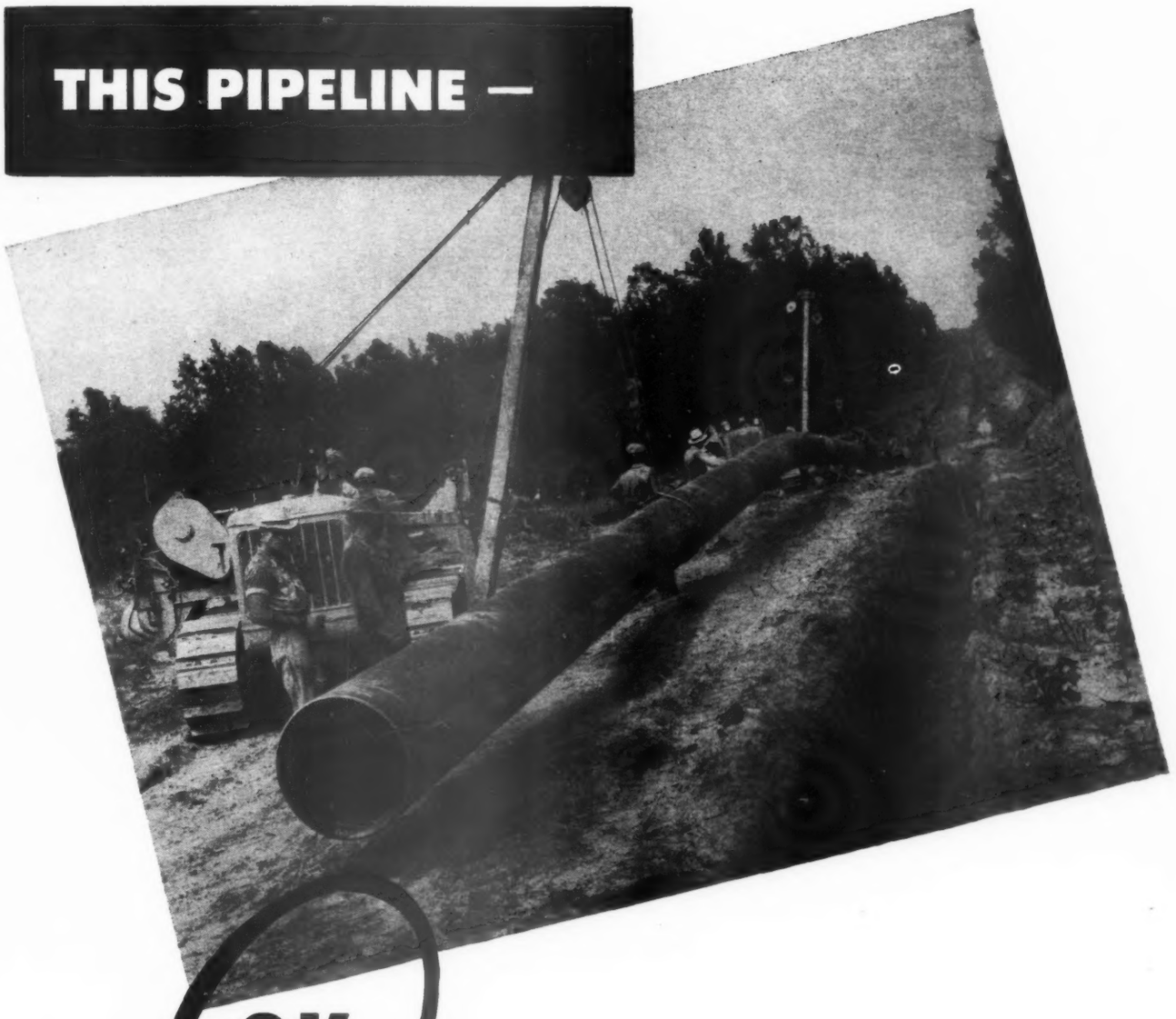
It has been rather well established that the wearing characteristics of gray cast iron are fundamentally tied in with its microstructure. In order to give good wear resistance, cylinders and piston rings must have a truly pearlitic matrix with a random distribution of the graphite flakes such as is illustrated in Plate 16, Fig. 1. Any deviation from such a structure is decidedly detrimental to the wear resistance. For example, the presence of free ferrite such as is shown in Fig. 2 lowers wear resistance considerably. On the other hand a distribution of the graphite other than random flake such as the eutectiform, as is shown in Fig. 3, gives exceedingly poor wear resistance. This type of distribution is always associated with free ferrite as shown in the photomicrograph.

Fortunately, the best physical properties and hardness are associated with the pearlitic matrix and random flake distribution of the graphite. Hence, we have found that for a minimum Brinell hardness of approximately 180 it is necessary to provide this structure. This hardness also provides sufficient strength in the casting to withstand the stresses imposed on it.

Addition of alloys to gray cast iron to refine and stabilize the pearlitic matrix is sometimes desirable. To do this the addition of a combination of nickel, chromium, and molybdenum is often practiced. The general rule being that carbide stabilizing elements such as chromium added in combination with grain refining elements such as nickel and molybdenum give excellent wear characteristics. Because phosphorous forms a hard iron-phosphide eutectic (Steadite) that is held firmly in the matrix it in many cases also is added to improve wear resistance.

A booklet on "Wear" by Dr. Francis P. Bundy, T. E. Eagan, and R. L. Boyer.

THIS PIPELINE —



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which will cover this subject from the angle of the physicist, the metallurgist, the designer, and lubrication engineer, is in preparation and will be available around the first of 1945.

Pressures up to 6000 lb. have been used with cast iron liners and cast iron rings. For higher pressures hardened steel cylinder bores or plungers with bronze rings are used.

The proportions of the piston rings are important but the ideal is almost impossible to accomplish in compressor cylinders. In general, the narrower the face of the piston ring the better, as the pressure loading on the cylinder wall is directly proportional to the width of the ring. Scientific proof of this will be presented in the booklet on "Wear" referred to.

A narrow faced ring will therefore generate proportionately less frictional heat on the cylinder wall, will seal better in that it can follow slight deviations in the cylinder wall better, and it has correspondingly less inertia for pounding out the sides of the ring grooves. This ideal is difficult to attain in many high pressure applications. The narrow faced ring is inherently a snap ring and since most high pressure cylinders are of small diameter the depth of the ring is therefore limited to what can be snapped over the piston without distortion.

Where conditions of cleanliness and good lubrication are present these small section snap rings have given excellent service, however, where certain amounts of condensate are unavoidable and where appreciable amounts of heavy lubricants cannot be tolerated in the finished product, rings of resinous plastic, of carbon, or mixtures thereof, give better results than metal rings. Due to their low physical properties and the desirability of getting as much ring depth as possible, these rings are made segmental with a steel expander ring underneath. These rings are usually in three segments with three joints, therefore, it is important that they be of the sealed joint type. Bronze rings of this type are very satisfactory where the gas is clean enough. Any soft metal used as a ring has a tendency to load up with dirt and form a lap for the cylinder bore. Cast iron segmental rings have no advantage over the cast iron snap rings except they have more depth and under the same conditions of wear last longer.

Compressor pistons are scarcely ever artificially cooled because of the moderate temperatures encountered. However, the temperatures they do encounter vary with the compression ratio so that to be safe the piston to cylinder clearance is usually made to take care of the highest ratio that is likely to be encountered, or about 6 to 1, giving about 285 to 300°F. temperature, and a clearance of 0.0015-in. per in. diam., with a plus and minus tolerance of 0.002 in. to 0.010 in., depending on the diameter of the piston. Since high pressure cylinders are small in diameter this clearance is so small that the effect of misalignment with the crosshead is not enough to affect the running of the crosshead. If undue wear takes place on the bottom of the piston so as to tilt the crosshead enough to make it run hot, it can be corrected by turning the piston to a new bearing position. This can be done 3 or 4 times before the piston needs to be replaced.

As to the exact amount that a piston can be allowed to sag below the centerline of the crosshead, only experience with each individual design could guide the operator. The unit pressure on cylinder wall caused by the tension in the ring itself or the expander spring is so small in comparison to the pressure caused by the gas pressure as to be of no consequence. A unit pressure of 12 to 16 lb. per sq. in. is very satisfactory although higher pressures can be used with safety. With snap rings it is usually desirable to use a rather high tension as the ring will then have more follow up before it need be discarded.

The piston to cylinder fit has practically no effect on leakage past the rings. The trueness of the bore, the uniformity of wall pressure of the ring, and the flatness and perfection of the side surface of ring and groove are the main factors in leakage. The outer surface of the ring will in time "seat" itself into the cylinder bore but imperfections in the side surfaces will never correct themselves.

The number of rings on a piston is a function of the differential pressure handled. Only the first few rings toward the pressure are effective and the only reason for putting a large number of rings on a piston or rod is to have a reserve in case the first rings get worn to the extent of excessive leakage, so that

PLATE 15.

FIG. 1. Piston rod load and MIP curves.
Horsepower held constant at 200 B. hp. Differential pressure $P_2 - P_1 = \Delta P$. Piston [illegible] to keep [illegible] constant. Piston rod diam. = 3". Stroke = 14". Speed = 300 r.p.m. Gas forces only.

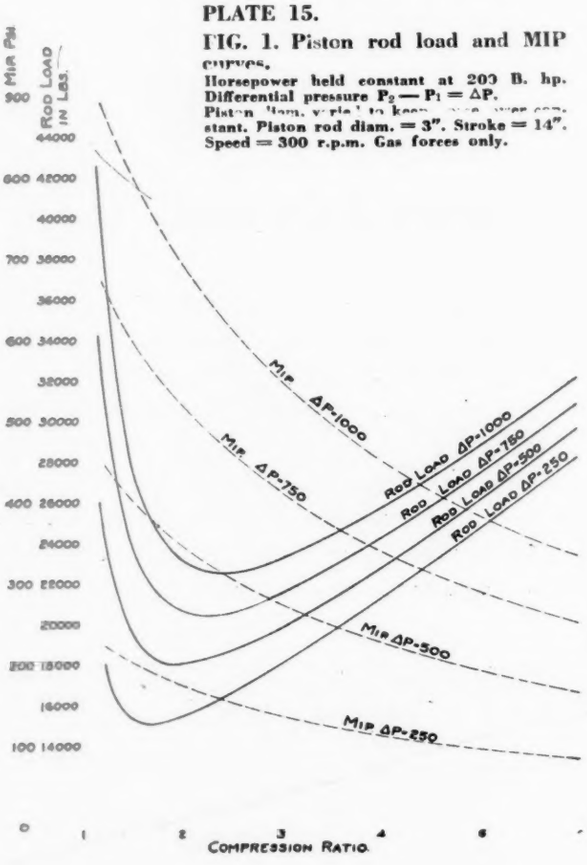
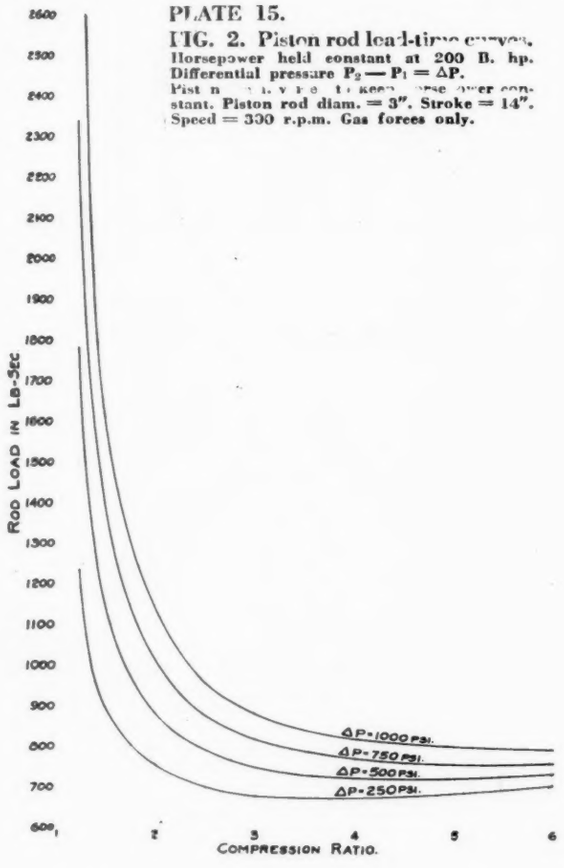


PLATE 15.

FIG. 2. Piston rod load-time curves.
Horsepower held constant at 200 B. hp. Differential pressure $P_2 - P_1 = \Delta P$. Piston [illegible] to keep [illegible] constant. Piston rod diam. = 3". Stroke = 14". Speed = 300 r.p.m. Gas forces only.



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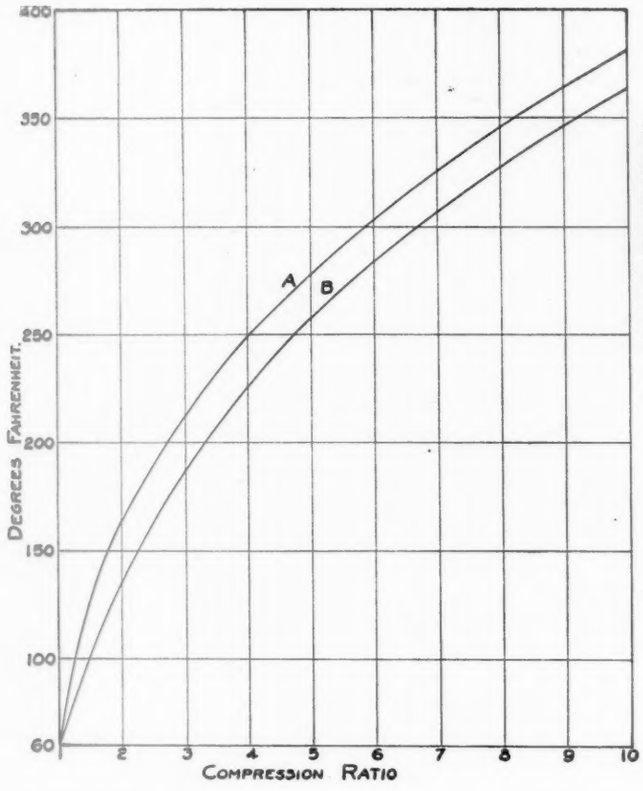

PLATE 14. (Left) Temperature rise due to compression. Curve A is based on G. G. Brown's enthalpy-entropy curves for 0.60 gravity gas. P_2 = 14.7 lb. per sq. in. abs. T_0 = 60° F. Curve B is based on perfect gas laws.

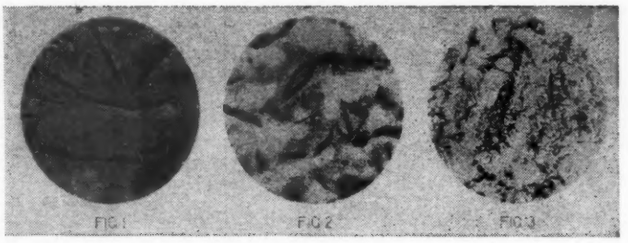

PLATE 16.

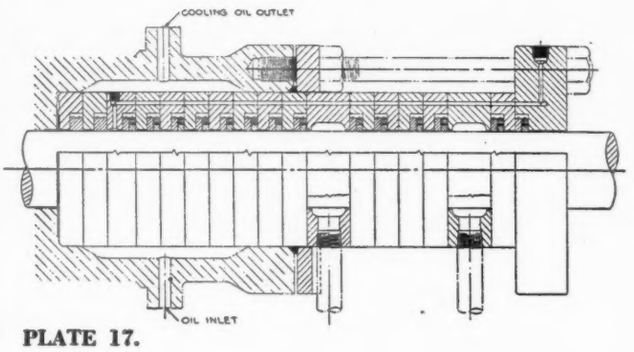

PLATE 17.

a longer run could be made before shutting down; 6000 lb. have been successfully handled with six rings.

The side clearance in ring grooves should be as low as can be used without sticking. Excessive side clearance will allow the ring to slap back and forth in the groove and eventually the impact will pound out the ring lands at an ever-increasing rate.

Ring gap is determined by the maximum temperature at which the piston is to be operated and should be as small as can be used without the ends butting at the maximum temperature. A good figure for this is 0.003-in. per in. of diam.

● **Piston rods and rod packing.** Piston rods, except for some special reason such as handling corrosive gases, are usually made of about a 1045 steel for differential pressures up to about 2000 to 3000 lb. Above this they are case hardened. The hardness should increase with the pressure. Where corrosive gases are encountered a solid stainless steel rod has been used but due to the tendency for this material to work harden under friction and the difficulty of maintaining a uniform degree of friction on all portions of the rod, they have a tendency to warp. It is now considered better practice to make the rod of ordinary steel and metal spray it with the desired composition of stainless material. This practice not only gets away from the warping but due to the porosity of the sprayed surface is much better for holding lubrication.

On high pressure work rod packing is almost entirely of the metallic segmental ring type and there have been so many different designs used that it would be impossible to cover them all in this paper. The cases are usually of cast-iron rings with ring recesses cut in one side of them, which when stacked up axially form a series of ring grooves. Thus a packing for any desired pressure can be built up out of the same parts. At the outer end is a flange that holds the sections and at the same time holds the packing in the head recess by means of bolts into the head. There is no particular grade of metal needed in the case, other than that it be strong and close grained. The metal in the rings, however, is even more sensitive than piston rings. Piston rings almost always ride on a cast-iron or hardened-steel surface while rod packing rings ride on all sorts of variations in rod material. The rings are segmental of a great variety of designs, often two in a groove, with joints mismatched and held together by a long slender coil spring called a garter spring with ends hooked together in a groove on the outer periphery of the assembled ring. Cast iron is the most common material used although various bronzes, Bakelite, Micarta, carbon, etc., are all used where the conditions demand. All the conditions, such as unit pressure, side clearance, etc., that apply to piston rings, also apply to rod packing rings.

Rod packing has one feature for high pressure work that would be impractical for piston rings, that is it can be built in as many stages as desired. (See Plate 17.) A spacer ring can be inserted at any place in the packing with a vent connection to the outside that can be piped to any desired lower stage. This way the high pressure can be absolutely prevented from reaching the outer sections of the packing.

If the inner or high pressure stage gets to leaking too badly the vent connection will become hot and warn the operator before disaster happens. The last vent connection is often connected to atmospheric pressure and piped outside the building so that it is practically impossible to leak gas inside the building. Plate 17 shows a three-stage packing with the first vent carried to a lower stage pressure or if single stage to the suction pressure, and the second carried to atmosphere. In many cases the outer stage is made of ordinary soft packing that can be tightened up "bottle tight" during a shutdown period but must be loosened again when starting up.

● **Compressor valves.** In dealing with this heading we will consider only the almost universally used plate type of valve. Plate 18, Fig. 1, shows an example. A is the valve seat with concentric circular ports. B is the hardened steel valve plate that covers the ports. C is the valve guard that contains the spring pockets, guides the valve, and limits the lift of the valve. D are springs that return the valve to the seat. E is a valve cap bolted to the cylinder body or head and holds the valve to its seat by means of a center jack bolt F acting on a spider G or directly on the periphery of the spider as shown in Fig. 2. The lift of the valve must be definitely limited or the impact between the valve and the seat and guard will cause undue valve breakage; ⅛-in. lift is about the maximum that can be used, however, this varies somewhat with the number of strokes per minute, the differential pressure on the seat, and the velocity of the gas. As the lift is limited, the effective

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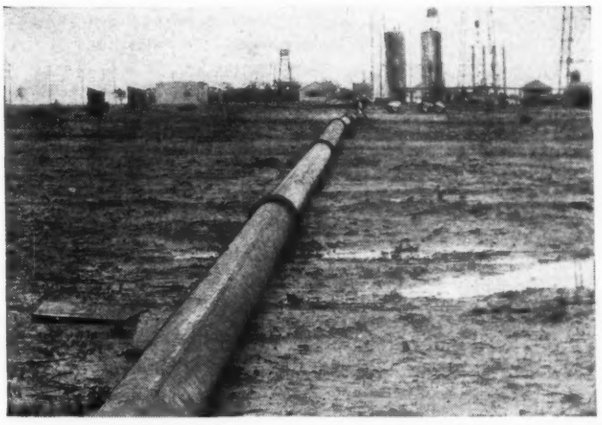

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port width is limited accordingly. Referring to Fig. 3 it is obvious that for a lift of ⅛-in. a port width of more than ¼-in. would not gain any increased net area but would limit the number of ports that could be used in a valve of given outside diameter. For a given valve velocity the outside diameter of the valve would be increased by wide ports thereby limiting the number of valves that could be used in a cylinder and also adding decidedly to the clearance volume.

As a general rule it is desirable to keep the gas velocity as low as possible to avoid unnecesary work loss; however, the ideal is impossible to attain in most cases. Because larger valves on these small bores mean rapidly increasing clearance volume in the valve pockets, it is difficult to get the velocity below 5000 to 6000 ft. per min. In adding to clearance a vicious circle is started, as the larger the clearance the larger the cylinder bore for the same capacity and therefore the larger the loading on bearings and other parts and the lower the mechanical efficiency. This applies to all designs with side outlet valves but not to designs as shown in Plates 6, 7, 10, and 11. Most manufacturers have certain ranges of cylinder bores in any one design. It is obvious, therefore, that the larger bores in any series will have higher valve velocities than the lower ones.

Other limitations have to do with relative spring loading, spring frequency, and gas velocity. If the velocity is too low the kinetic energy of the gas impinging on the valve plate is not enough to overcome the spring load sufficiently to hold the plate against the guard, then the plate will only partially open and develop a high frequency "flutter" that damages the springs and adds to plate breakage. The seat area should be as low as mechanically safe, therefore, the seat unit pressure will be as high as can be tolerated without undue seat deterioration. When the valve is closed, the pressure on the back side of the valve times the sum of the port area and the seat area must be overcome by pressure times port area alone from the underside. From this it can be seen that to open the discharge valve the pressure inside the cylinder must increase above the discharge pressure enough to overcome the differential of the seat area When the valve cracks open this higher pressure is immediately applied to the full area of the plate, which imparts to it a high velocity and a corresponding high degree of impact against the guard.

The thickness of the plate should be as low as can mechanically bridge the port without undue stress and have reasonable seat life. The heavier the plate, the greater the impact on both guard and seat. For pressures up to 2500 lb. and a port not over ¼-in. wide, a properly heat treated chrome vanadium plate of a thickness of 1/16 in. is satisfactory. For higher pressures proportionately thicker plates or narrower ports are necessary.

A great many times valves and compressor passages are unjustly blamed for power losses when inadequate and improperly designed piping and headers leading to and away from the compressors are really at fault. This is an easy mistake to make when looking at an indicator diagram from the compressor cylinder alone. Plate 19 shows an indicator diagram reproduced from an actual diagram from a gas pipe line compressor. The suction pressure is about 380 lb. yet a good part of the suction line shows 20 lb. below this. The discharge pressure is 600 lb., yet most of the discharge line is from 40 to 60 lb. above this pressure.

This card represents a work loss of 18 per cent of what it should have been. However, when a simultaneous diagram is taken from the discharge and suction passages at their outlet and inlet flanges and superimposed upon the digram from the cylinder, a different story is presented. The heavy line A is the discharge line from the cylinder and the dotted line B is from the discharge passages. The difference between these two is all that can be charged to internal resistance in the compressor and averages only about 10 lb. where the piston velocity is highest and trails off to nothing near the end of the stroke where the piston velocity is low. The suction line shows a similar condition although not so exaggerated due to the lower density of the gas. The actual work loss chargeable to the cylinder construction is only 6.4 per cent. This loss condition is partly due to inadequate piping and headers close up to the cylinders and the suction and discharge pressures have been disturbed by nearby cylinders taking suction and discharging simultaneously. The headers were inadequate to take care of this condition.

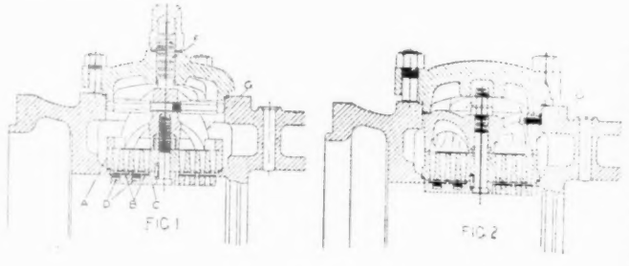
Another cause is pipe line pulsations caused by too small a line, therefore too high a velocity, in the line leading away from the station. This is evidenced by the fact that toward the end of the discharge stroke the pulsation was moving away from the compressor and pulled the discharge pressure in the cylinder below the normal discharge pressure. Just before the crossing of these two pressure lines the corresponding pulsation was back toward the compressor cylinder and added to the loss in work above the discharge pressure line. Few designers of compressor stations in the past have realized how serious a power loss this condition can cause.

From the foregoing it is obvious that due to the almost infinite variations in pressures, rotative speeds, specific gravity of gases, etc., coupled with limitations as to gas velocities, valve lifts, spring loadings, and frequencies, compressor valve design is largely made up of compromises.

● **Lubrication.** The lubrication of compressor cylinders is another complicated problem because of the great variation in the services for which they are used. In some cases the lubricant that would give the best wear resistance on the rings and cylinder bores would work through the crankcase and gum up crankcase bearings, etc. In repressuring work such oils will clog up the sand at the bottom of the input wells and result in excessive costs for clean-out. In many other cases the use of the best form of lubricant will discolor or otherwise harm the product handled. In still other cases when compressing air for certain refinery processes, due to the fire hazard in the discharge lines, tanks, etc., a hydrocarbon lubricant cannot be used at all. In such cases soap solutions and other non-inflammable fluids are used.

Cases are on record where the life of piston rings has been extended from a

PLATE 18.



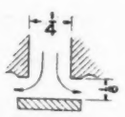
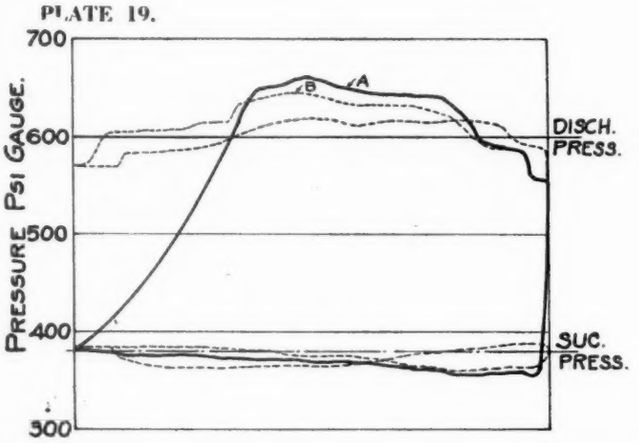


FIG. 3.

PLATE 19.



few hours to 2½ or 3 years by a change in the lubricant alone. In general, compressors for the services under consideration are not very high in rotative speed and, therefore, the use of rather high viscosity lubricants are not harmful to the mechanical efficiency as they would be in high speed machinery, as for instance automotive type engines. It is, therefore, advisable to use a rather high viscosity additive oil with as great a film strength as possible. As stated before, pressures up to 10,000 lb. per sq. in. are encountered between ring and cylinder wall and at such pressures if scuffing once starts it is almost impossible to heal. The use of a heavy oil also improves the seal between the ring and cylinder wall and ring lands.

There is a belief that viscosity of lube oil is reduced by absorbing high pressure gases directly. This is doubtful and no allowance is made for this in selecting oils. The problem of having liquids condense on the cylinder walls is very common and these liquid hydrocarbons very definitely damage or destroy the oil film. One way to avoid this is to increase the number of stages of compression, thus lowering the compression ratio in each stage and drop out and trap off the condensates in intercoolers. Another is to keep the cylinder wall hot enough to prevent the condensation on the wall itself. As a last resort, if condensation cannot be avoided, a lubricant must be used that is not affected by the hydrocarbons. In some cases carbon rings with no lubrication whatever have been used.

It is also believed in some quarters that the viscosity of lubricating oil is reduced by pressure. The opposite of this is true. The viscosity is increased by pressure and theoretically pressure can be increased to where the oil will solidify. Paraffin oils are less affected by this action than naphthenic base oils but since no harmful effects have been encountered in compressors covered in this paper, the pressures to produce solidification must be extremely high. The rings have no effect on this as the ring pressure on the wall is the same or less than the gas pressure.

In conclusion it must be quite evident from the foregoing that compressor design presents complicated problems, due to the large number of variables encountered, such as horsepower, gas capacity, discharge pressures, compression ratios, gas composition, temperatures, line pulsations, number of stages, etc. It is almost impossible to standardize because demands vary from suction pressures of minus 28 in. of mercury to 6000 lb. and in some cases as high as 15,000 lb. discharge pressure. To somewhat mitigate the almost infinite variation most builders design for a certain range of diameters in one cylinder body. In this way only the liner, piston, and rings need be changed within each range.

Every individual case must be engineered separately except where there is an addition to an existing plant or in rare cases where there is a duplication of an existing plant.

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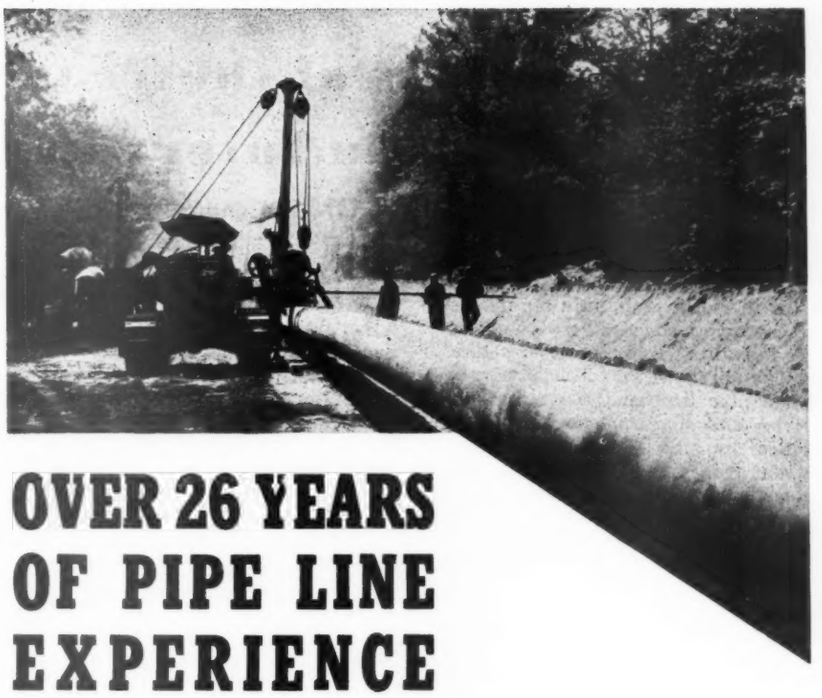

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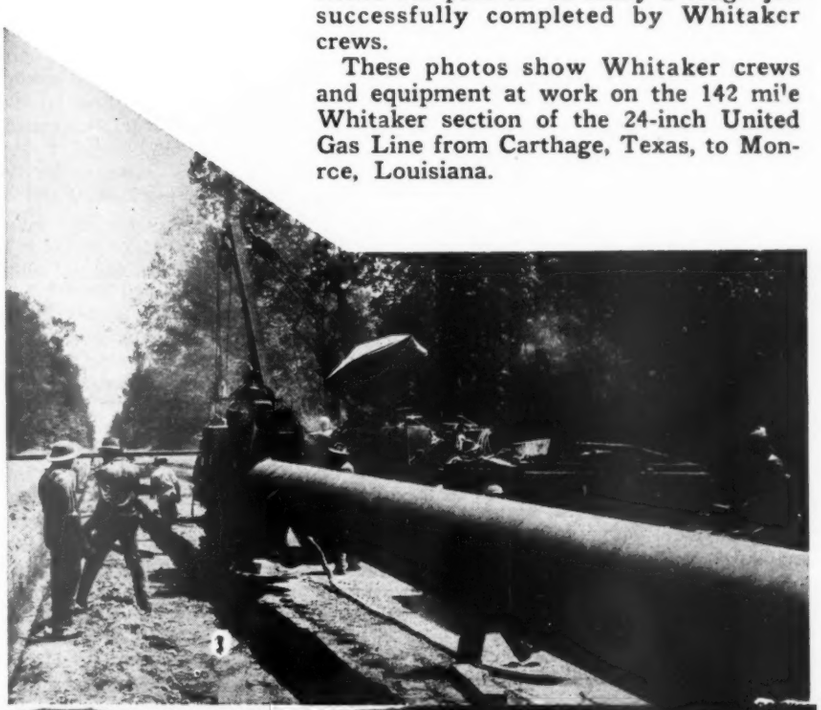

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Legal Aspects of the Transportation of Natural Gas in Interstate Commerce*

By MARSHALL NEWCOMB, General Attorney, Lone Star Gas Company

ONLY in recent years have the natural gas producing states of the southwest come to realize the real value of natural gas. The advent of the long distance interstate pipe lines and the recent discoveries and developments that make practical the utilization of natural gas for manufacturing by-products and chemicals have created a large demand for natural gas production and acreage. For many years interest in the petroleum industry centered almost exclusively upon oil, and to discover gas in the search for oil was considered a misfortune. The progress and growth of the natural gas industry, as well as the vicissitudes encountered in the process of this growth, are interestingly related in the dissenting opinion of Mr. Justice Jackson in the Hope Case.[1]

The wide and important uses made of natural gas in recent years have also created an awareness that wasteful practices of the past must be stopped. The states through their legislatures, regulatory agencies, and the Interstate Oil Compact Commission have shown increased energy in providing and applying laws and regulations to prevent both underground and surface waste of this valuable natural resource.

The long distance interstate pipe lines and the expanding interstate markets for natural gas prompted the Congress in 1938 to declare "that the business of transporting and selling natural gas for ultimate distribution to the public is effected with a public interest, and that federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest"; and the Congress provided an elaborate system for federal regulation of "the transportation of natural gas in interstate commerce—the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and . . . natural gas companies engaged in such transportation or sale."[2]

The depletion of gas reserves in the Appalachian area has created a serious shortage in the states of that region, and the states of Kansas, Oklahoma, Louisiana, and Texas have become major sources of supply for gas moving in interstate commerce.[3] In each of these states there have been advocates for state legislation that would prohibit the exportation of natural gas altogether, or limit the quantity that could be exported, or by discriminatory taxation discourage its transportation out of the state. Quite recently Louisiana has challenged in the Federal courts an order of the Federal Power Commission granting an interstate pipe line company authority to construct additional facilities for the exportation of gas from that state.[4] The decision of the United States Circuit Court of Appeals went against Louisiana but the case is now pending before the Supreme Court of the United States. Louisiana took the position that certificates of public convenience and necessity should not stand because they were issued to permit the exportation of gas for burning under boilers, an industrial use that is regarded as inferior and wasteful, and, therefore, the granting of the certificates were not in, but against, the public interest. The coal and railroad interests have taken the same view. They have consistently opposed the granting of certificates of public convenience and necessity by Federal Power Commission on the grounds that the use of natural gas for industrial and space-heating purposes constitutes a dissipation of the natural gas resources, and threatens the coal industry.[5] One may justifiably suspect that the opposition of the railroad and coal interests stems more from their desire to protect their own businesses from competition than from any real desire to husband the natural resources for so-called "superior" uses. However, in a case decided April 26, 1946,[6] the Federal Power Commission stated that the Commission had given careful consideration to the broad issues of public convenience and necessity raised by the intervening coal and railroad interests, who referred to the projects as segments of an over-all progressive encroachment of natural gas upon the commercial fields of solid fuels and stressed the view that natural gas should not be dissipated in large industrial plants where coal is available and can be readily and economically substituted. The Commission stated that it was cognizant of the necessity of conservation of the country's irreplaceable natural gas resources, and that considerations of conservation were material to the issuance of certificates under Section 7 of the Act.

I mention these activities, occurring in the field of federal regulation, because they have a direct bearing upon the quantities of gas that may in the future be exported from the producing states. To prohibit or restrict the utilization of natural gas for industrial and space-heating purposes will substantially reduce the quantity exported. Such action would unquestionably create an important impact upon the economy of the producing states and seriously affect the financial soundness of the companies that engage primarily in interstate transportation and sale of natural gas.

But it is my main purpose to discuss the legal aspects of the exportation of natural gas from the state and not the federal angle. To this discussion I now turn.

The states should not proceed on the false premise that the exportation of natural gas to other states can be prohibited by state action. It is plainly not permissible for a state to deal with its natural gas on the supposition that its sale, transportation, and consumption in interstate commerce can be prohibited. Any law, regulation or taxation that has the practical effect of directly burdening, regulating or prohibiting the sale or transportation of natural gas in interstate commerce will represent a waste of time, energy, and money. Under our National Constitution, commerce in natural gas between the states can be neither prohibited nor regulated nor directly taxed by the states. In dealing with this subject, it must never be forgotten that, governmentally and economically speaking, each state is a part of an indissoluble nation. The welfare of the nation as a whole is paramount to the economic interests or grandeur of any particular segment thereof.

The early Confederacy was abandoned in favor of the United States under our present Constitution because it had been proved by actual experience that a strong, virile, and prosperous nation could not be created or maintained unless barriers to commerce between the states were eradicated and control of commercial intercourse between the states vested in the hands of a national authority that would be uninfluenced by the ambitions of a particular section or region.

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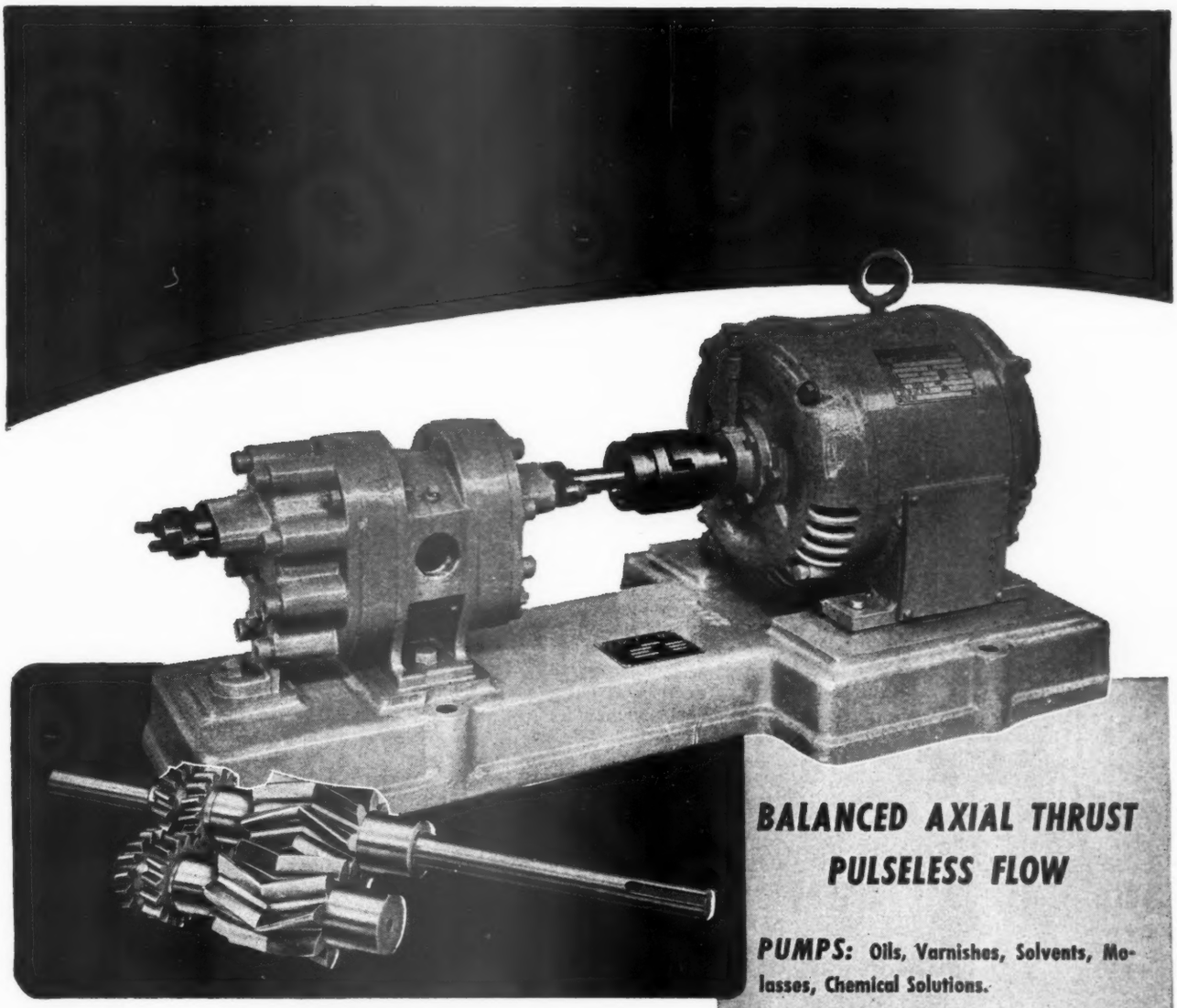
*Presented before Gas Division, Oklahoma Utilities Association, Oklahoma City, Oklahoma, September 21, 1945.

1. 320 U. S. 591, 630-639.
2. Natural Gas Act, 15 U.S.C.A. 717.
3. Figures obtained from a reliable source show that in 1943 the quantity of gas exported from the four states named was as follows:

Texas	305,656,000,000 cu. ft.
Oklahoma	69,596,000,000 cu. ft.
Kansas	76,219,000,000 cu. ft.
Louisiana	224,219,000,000 cu. ft.

These figures do not take into account the quantity of gas imported into each state. For instance, gas is imported from Oklahoma into Texas and from Texas into Oklahoma. Texas also imports gas from Louisiana and New Mexico.

4. Department of Conservation of State of Louisiana et al. v. Federal Power Commission, 148 Fed. (2) 746.
5. Tennessee Gas and Transmission Company, F.P.C. Opinion No. 93-A, Release No. 2269; and also Department of Conservation of State of Louisiana v. Federal Power Commission, 148 Fed. (2) 746.
6. Re: Hope Natural Gas Company, et al, F.P.C. Release No. 2417, Opinion No. 114.



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One of the principles of the Constitutional Convention was to obtain and promote unobstructed commerce among the states. The inability of the National Government, as created by the Articles of Confederation, to deal effectively with commerce was one of the prime causes of the call for the Constitutional Convention. "It may be doubted," said Marshall, "whether any of the evils proceeding from the feebleness of the Federal government contributed more to that great revolution which introduced the present system than the deep and general conviction that commerce ought to be regulated by Congress."[7]

In the commerce clause the people of the United States sought protection of individual liberty of trade and all of its incidents from the stifling and conflicting regulations of the several states. Few things were better known, remarked Daniel Webster in the course of his argument in Gibbons v. Ogden,[8] than the immediate causes which led to the adoption of the present Constitution; and he thought nothing clearer than that the prevailing motive was to regulate commerce; to rescue it from the embarrassing and destructive consequences resulting from the legislation of so many different States, and to place it under the protection of a uniform law.

By the Confederation, divers restrictions had been imposed on the States; but these had not been found sufficient. No State, it was true, could send or receive an embassy; nor make any treaty; nor enter into any compact with another State, or with a foreign power; nor lay duties, interfering with treaties which had been entered into by Congress. But all these were found to be short of what the actual condition of the country required. The States could still, each for itself, regulate commerce, and the consequence was, a perpetual jarring and hostility of commercial regulation—a welter of iniquitous laws and impolitic measures—"from which grew up a conflict of commercial regulations, destructive to the harmony of the States, and fatal to their commercial interests abroad."[9]

The great state of Oklahoma in 1907 enacted a law that prohibited the granting of a charter to, or the exercise of the right of eminent domain, or the right to use the highways of the State by any corporation engaging in the transportation of natural gas unless such corporation should agree that it would not connect with, transport to or deliver natural gas to individuals, associations, co-partnerships, companies or corporations engaging in transporting or supplying natural gas to points, places or persons outside the State. A similar restriction was imposed upon foreign corporations by providing that they should not be licensed or permitted to conduct business within the State.

The Kansas Gas Company was engaged in purchasing gas in Oklahoma and transporting it by pipe line to points of consumption in Kansas. Other corporations were similarly engaged. Upon the suit of these corporations to enjoin enforcement of the Act, the court was required to directly decide the question of whether Oklahoma could prohibit the exportation of gas by private concerns to points of consumption in Kansas. Oklahoma complained that it needed all of its gas for use by its own citizens. It showed that its population was steadily increasing, that it had no domestic fuel except coal and natural gas; that its supply of coal was growing rapidly more costly to produce; that the petroleum oil produced in the State was practically all transported out of it; and that substantially the only natural, practicable, usable fuel, both for domestic and industrial use, was natural gas. Oklahoma, by evidence, painted a dismal picture for itself and its citizens if the existing and planned exportation of natural gas in great quantities were permitted to continue.[10]

In summarizing the effect and intent of the legislation, the Supreme Court of the United States said:[11]

"The statute presents no embarrassing questions of interpretation. It was manifestly enacted in the confident belief that the State had the power to confine commerce in the natural gas between points within the State, and all of the rights conferred on domestic corporations, all of the rights denied to foreign corporations, were means to such end."

Oklahoma contended that it had a right to conserve its natural resources for its own citizens and the right to preserve a common supply for the equal uses of all those who may by law resort to it. In denying to Oklahoma the asserted power, the court said:

"If the States have such power a singular situation might result. Pennsylvania might keep its coal, the Northwest its timber, the mining States their minerals. And why may not the products of the field be brought within the principle? . . . If one State has it, all States have it; embargo may be retaliated by embargo, and commerce will be halted at state lines. And yet we have said that 'in matters of foreign and interstate commerce there are no state lines.' In such commerce, instead of the States, a new power appears and a new welfare, a welfare which transcends that of any State. But rather let us say it is constituted of the welfare of all of the States and that of each State is made the greater by division of its resources, natural and created, with every other State, and those of every other State with it. This was the purpose, as it is the result, of the interstate commerce clause of the Constitution of the United States."[12]

In 1919 West Virginia enacted a statute that taxed the transportation of natural gas and oil by pipe lines. The statute was assailed on the grounds that it imposed a tax upon commerce among the States. The Supreme Court of the United States declared it invalid as to both oil and gas transported in interstate commerce.[13] Because of the rather devious method of levying and collecting the tax, the highest court of the State ruled that it applied only to interstate commerce. But the Supreme Court said that a state tax to be valid "must not in its *practical* effect and operation burden interstate commerce."[14]

Any valid tax upon natural gas that ultimately moves in interstate commerce must be levied upon the production, that is, before the gas is sold in or begins its journey in interstate commerce, and it must be nondiscriminatory in its operation.[15]

Again in 1919 West Virginia enacted a statute that was intended, through regulation of pipe line companies, to compel the retention within West Virginia of all natural gas there produced, which might be required for local needs. The facts showed that the effect of the statute was such that, directly and immediately, it would work a large curtailment of the volume of gas going into the states of Ohio and Pennsylvania and, in a few years, with increasing demand and decreasing production, would work a practical cessation of the interstate stream which it was the object of the suits to protect. Ohio and Pennsylvania brought suit to enjoin enforcement of the statute on the grounds that it directly interfered with interstate commerce. They rested their right to relief on the grounds that to enforce the statute would subject them to irreparable injury in respect to many of their public institutions and governmental agencies which long had been and were then using natural gas produced in West Virginia.[16]

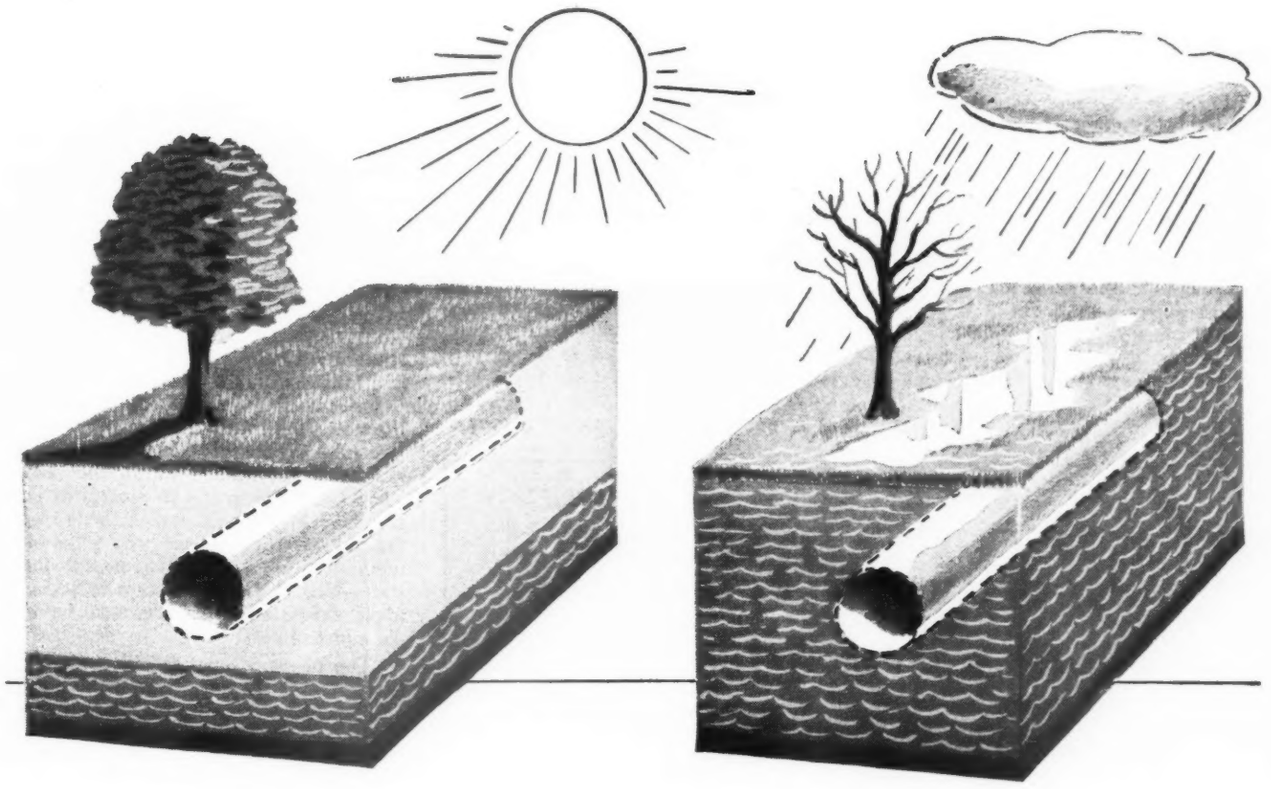
In its opinion the court recites the history of natural gas in West Virginia, showing that initially large quantities of gas were available, more than enough to supply all the demands of West Virginia consumers and those of Ohio and Pennsylvania. Gradually there was a diminution in the supply due to large withdrawals by interstate as well as intrastate public utility pipe lines. The point was reached where all demands of West Virginia consumers could not be supplied without limiting the amount of gas transported into Pennsylvania and Ohio. Each suit presented the direct issue between two states as to whether one might withdraw a natural product, a common subject of commercial dealing, from an established current of commerce moving into the territory of the other.[17]

The court ruled that the challenged statute was invalid. It rested its decision upon the Commerce Clause, and in the course of its opinion, said:

7. Brown v. Maryland, 12 Wheat. 419.
8. 9 Wheat. 11.
9. Gibbons vs. Ogden, 9 Wheat., at page 224.

10. It is of passing interest to note that the concern thus evidenced by Oklahoma in 1907 has proved unwarranted by the fact that natural gas is now being supplied to its citizens in abundant quantities and is also being exported from Oklahoma to Texas, Kansas and other points."
11. Oklahoma vs. Kansas Natural Gas Co., 7221 U. S. 229, 250.
12. Id. p. 255.

13. Eureka Pipe Line Co. v. Hallanan (Oil), 257 U. S. 265, 266, and United Fuel Gas Co. v. Hallanan (Gas), 257 U. S. 277.
14. Id. p. 272.
15. Hope Natural Gas Co. v. Hall, 274 U. S. 284, 286; Parker v. Brown, 317 U. S. 341, 360, 361.
16. Pennsylvania v. West Virginia, 262 U.S. 553.
17. Id. p. 591.



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"Natural gas is a lawful article of commerce and its transmission from one State to another for sale and consumption in the latter is interstate commerce. A state law, whether of the State where the gas is produced or that where it is to be sold, which by its necessary operation prevents, obstructs or burdens such transmission is a regulation of interstate commerce—a prohibited interference."[18]

The court considered and overruled the contentions that since the pipe line companies were public utilities within West Virginia the latter State had the right to require them to provide reasonably adequate service within reasonable territorial limits even to the exclusion of adequate service to consumers beyond the limits of West Virginia; that natural gas was a product of the State, had become a necessity therein, the supply was waning and no longer sufficient to supply local needs and be used abroad, and the Act was therefore a legitimate measure of conservation in the interest of the people of the State.

Natural gas is property subject to absolute private ownership. Usually it is privately owned, sold and transported pursuant to contracts between private parties and by means of facilities privately owned and controlled. This characteristic distinguishes it from wild animals in which there can be no private ownership. The state may prohibit transportation of the latter in interstate commerce.[19]

By statutory enactment Louisiana declared all shrimp and parts thereof within its waters to be the property of the state, and sought to regulate their taking and reduction to private ownership. It granted the right to take, can, pack, and dry shrimp to residents and also to corporations, domiciled or organized in the state, operating a canning or packing factory or drying platform therein. The Act made it unlawful to export from the state any shrimp from which the heads and hulls had not been removed. But, in order that all its inhabitants "may enjoy the state's natural food product," the Act declared it lawful to ship unshelled shrimp to any point within the state. Thus Louisiana sought to protect its important and valuable shrimp beds from the ravages of canners who exported them to canneries located outside that state. What Louisiana sought to accomplish was stated in her argument before the court, thusly:[20]

"The primary purpose of the statutes is to increase the industries of the State, develop its resources, and add to its wealth and prosperity, by causing to be located within its borders the necessary plants for canning and packing oysters and drying and canning of shrimp, and for the manufacture of fertilizer from the hulls of the shrimp, to be used for the benefit of the State, and primarily to be sold within its borders."

The rulings of the court, in answer to this argument, are significant in view of the quite similar arguments advanced by proponents of state action to stop the exportation of gas in order that industries might be attracted to the producing states.

One challenging the validity of a state enactment on the ground that it is repugnant to the commerce clause is not necessarily bound by the legislative declarations of purpose. It is open to him to show that in their practical operation its provisions directly burden or destroy interstate commerce. . . . In determining what is interstate commerce, courts look to practical considerations and the established course of business. . . . Interstate commerce includes more than transportation; it embraces all the component parts of commercial intercourse among States. And a state statute that operates directly to burden any of its essential elements is invalid. . . . A state is without power to prevent privately owned articles of trade from being shipped and sold in interstate commerce on the ground that they are required to satisfy local demands or because they are needed by the people of the State.[21]

Many other forms of state legislation that operated to regulate or hinder free intercourse between the States have been declared invalid. Rather recently New York sought to protect its farmers and

18. Id. pp. 596-597.

19. Greer v. Connecticut, 161 U.S. 519; and see dissenting opinion in Foster v. Haydel, 278 U.S. 1, 14.
20. Foster v. Haydel, at p. 8.
21. Id. p. 10.

STOPS CORROSION

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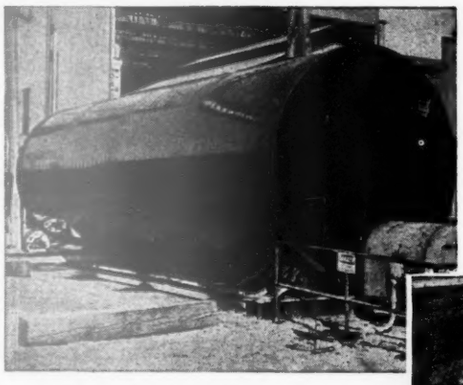

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those engaged in the dairying industry from the unfair competition of cheap milk imported from other States. It sought to protect the prosperity of the New York farmers by regulating the price to the farmers of milk produced and sold within the State, and by providing for the equalization of the cost of domestic and imported milk. The Act prohibited dealers from selling in the State milk produced outside the State where such milk was purchased from the producer at less than the minimum price fixed for similar milk produced within the State. In striking down this law the Supreme Court said:[22]

"... a chief occasion of the commerce clauses was 'the mutual jealousies and aggressions of the States, taking form in customs barriers and other economic retaliation.' Farrand, Records of the Federal Convention. vol. II, p. 308; vol. III. pp. 478, 547, 548; The Federalist, No. XLII; Curtis, History of the Constitution. vol. I. p. 502; Story on the Constitution. Sec. 259. If New York, in order to promote the economic welfare of her farmers, may guard them against competition with the cheaper prices of Vermont, the door has been opened to rivalries and reprisals that were meant to be averted by subjecting commerce between the States to the power of the nation. "... To give entrance to that excuse would be to invite a speedy end of our national solidarity...."

States may adopt and enforce all needed regulations for the conservation of natural gas so long as such regulations apply to intrastate transactions and before interstate commerce begins.

From the litigation provoked by various state conservation statutes, it has been judicially declared that a state has the power to shut in an oil well when casinghead gas is not used;[23] close in a gas well when the gas is used for making natural gasoline and the residue is dissipated;[24] permit the use of gas for one beneficial purpose and deny its use for another beneficial purpose;[25] exclude from the channels of commerce illegally produced oil;[26] restrict the flow of oil to prevent above ground or surface waste and conserve or equally distribute reservoir energy;[27] restrict the flow of oil so that each common owner may have a reasonable opportunity to recover his fair share;[28] and, limit the number of wells to be drilled on a given amount of land when such limitation does not

22. Baldwin v. G.A.F. Selig, 294 U.S. 511, 522, 528.
23. Ohio Oil Company v. Indiana, 177 U.S. 190; Bandini Petroleum Co. v. Superior Court, 284 U.S. 8.
24. F. C. Henderson, Inc. v. Railroad Commission, 56 Fed. (2) 218.
25. Henderson v. Thompson, 300 U.S. 258; Walls v. Midland Carbon Co., 254 U.S. 300; Lindsley v. Natural Carbonic Gas Co., 220 U.S. 61.
26. Thompson v. Spear, 91 Fed. (2) 430; Griswold v. The President 82 Fed. (2) 922; Panama Refining Co. v. Railroad Commission, 16 Fed. Supp. 289.
27. Champlin Refining Co. v. Corporation Commission, 286 U.S. 210; Railroad Commission of Texas v. Rowan and Nichols Oil Co., 310 U.S. 573.
28. Ohio Oil Co. v. Indiana, 177 U.S. 190; Walls v. Midland Carbon Co., 254 U.S. 300; Railroad Commission of Texas v. Rowan and Nichols Oil Co., 310 U.S. 573; Corzelius v. Harrell, 186 S.W. (2) 961.

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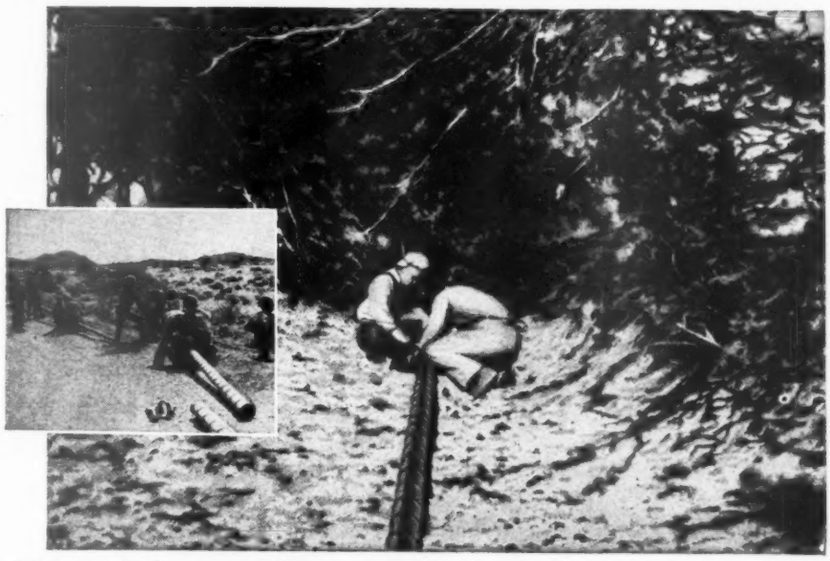

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amount to confiscation of private property.[29]

This specific enumeration of the powers that a State may exercise in conserving oil and natural gas by no means exhausts the field in which State action in such matters has been or may be sustained. They are merely illustrative. Such regulations are not regulations of interstate commerce because they apply to production and before commerce has commenced. A restriction of production moreover is not aimed at commerce. It forbids the production of the article, not its export to another State after production.[30] The diminution of the volume of exports in the one case and of imports in the other is incidental and indirect. Its effect is wholly collateral to the main purpose of the statute. Thus, in the Champlin Refining Company case the court pointed out that the challenged regulations "apply only to production and not to sales or transportation of crude oil or its products. Such production is essentially a mining operation and therefore is not a part of interstate commerce even though the product obtained is intended to be and in fact is immediately shipped in such commerce." But such regulations must not operate to take the property of one and give it to another or seriously to impair, under the guise of regulation, either the rights of property protected by the Fourteenth Amendment,[31] or the right to engage in interstate commerce.

29. Railroad Commission of Texas v. Rowan & Nichols Oil Co., 310 U.S. 573.

30. Parker v. Brown, 317 U.S. 341, 360, 361.

The Federal government has not undertaken to directly regulate the production or conservation of natural gas and oil.[32] The Natural Gas Act expressly excludes from its terms intrastate transportation or sale of natural gas, local distribution of natural gas, and the production or gathering of natural gas.[33] It does authorize Federal Power Commission to assemble information and recommend to Congress further legislation that may appear to be appropriate to carry out compacts between the states dealing with conservation and to aid in the conservation of natural gas resources within the United States and in the orderly, equitable and economic production, transportation and distribution of natural gas.[34]

Recently the Supreme Court has said that the Natural Gas Act does not intrude on the domain traditionally reserved for control by state commissions; that the Congress recognized the legitimate interest of the states in the conservation of natural gas;[35] and that Federal Power Commission is precluded from exercising any control over the activity of producing or gathering natural gas.[36]

Those who advocate state action to discourage by taxation or prohibit by direct legislation the exportation of natural gas also decry federal encroachment in matters of oil and gas conservation and production. In my opinion the surest way to hasten federal regulation of the production and conservation of natural gas is to undertake to stop or seriously interfere with its transportation and sale in interstate commerce. Nothing is more definitely settled in the constitutional law of this nation than that the power of the federal government to regulate interstate commerce carries with it all power necessary to preserve, foster and protect that commerce. State action in the field of production and conservation has been sustained because of its local character and wide scope for local regulation, and, in my opinion, will be sustained in the future only so long as there is no substantial impairment of the national interest and no material obstruction of the free flow of commerce.[37]

31. Thompson v. Consolidated Gas Utilities Corp., 300 U.S. 55.

32. In Buford et al v. Sun Oil Co. et al, 319 U.S. 315, 319, the Supreme Court of the United States made the none too reassuring observation that "The Federal government, *for the present at least*, has chosen to leave the principal regulatory responsibility with the States but does supplement control." Citing the Connally Hot Oil Act, 15 U.S.C.A., Sec. 715.

33. 15 U.S.C.A., Sec. 717(b). But under this Act certain indirect regulations are accomplished; Colorado Interstate Gas Company v. Federal Power Commission, 324 U.S. —, 89 L. Ed., Advance Opinions, P. 807.

34. 15 U.S.C.A., Sec. 717j(a).

35. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 612-613.

36. Colorado Interstate Gas Company v. Federal Power Commission, 324 U.S. —, 89 L. Ed., Advance Opinions, P. 807, 819.

37. Parker v. Brown, 317 U.S. 341, 360-363.

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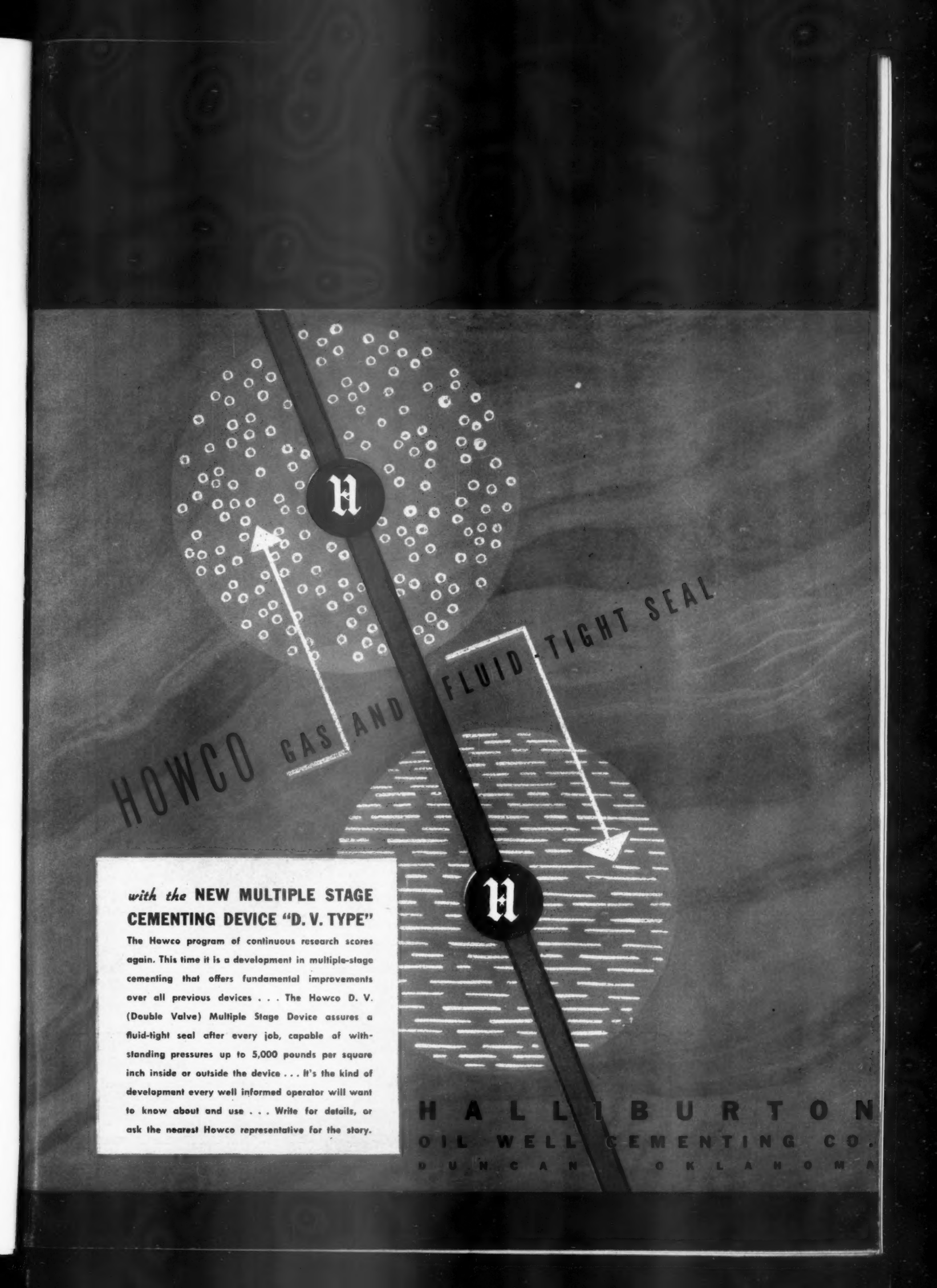

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